PETROLEUM MARKETING COMMISSION

403/262-8808
Telex: 03-821978
1900, 250 - 6th Avenue S.W.
Calgary, Alberta, Canada
T2P 3H7

February 29, 1984

INFORMATION BULLETIN RE ALBERTA COST OF SERVICE

The Alberta Cost of Service Information Bulletin for the month of January, 1984 is attached.

The Information Bulletin consists of:

1. Copies of any special Orders or Determinations issued by the Commission during the month with respect to Alberta Cost of Service, and notice of any Statements of Objection which have been received during the month; and

2. Alberta Cost of Service Determinations for the month.

In the case of gas intended to be removed from Alberta, the cost of service determined under Section 11(1), 15(3)(a) and 15(5)(b)(i) of the Natural Gas Pricing Agreement Act for each month is based on estimated figures for that month, adjusted to allow for differences between the estimated and actual figures for the previous month.

In the case of gas intended for consumption within Alberta, the amount estimated as cost of service under Sections 11(2)(a)(ii) and 15(3)(b)(i) of the Act were made under the Commission's general directive for the Alberta cost of service.

All determinations are on gross or higher heating value on a dry basis at 15°C and an absolute pressure of 101.325 kPa (kilopascal).

Yours very truly,

ALBERTA PETROLEUM MARKETING COMMISSION

R D Hall

R. D. Hall
Vice-Chairman

Attachment

INFORMATION BULLETIN
ALBERTA COST OF SERVICE DETERMINATION
PURSUANT TO THE NATURAL GAS PRICING AGREEMENT ACT
MONTH OF JANUARY, 1984

Section 15(3)(a)	Cents Per Gigajoule (GJ)*
Alberta and Southern Gas Co. Ltd.	
- Category A	35.875
- Category B	31.591
- Category E	26.586
Canadian Montana Pipe Line Company	49.197
Canadian Montana Gas Company Limited	49.193
Consolidated Natural Gas Limited	24.291
ICG Resources Ltd.	56.602
Many Islands Pipe Line (Canada) Limited	
- Purchased Gas	14.459
- North Sibbald (Agent)	2.595
- Saddle Lake	17.280
- Esther	10.441
Pan-Alberta Gas Ltd.	
- Basic	28.039
- Delivery Points - Joarcam	41.307
- Chinchaga North	38.847
- Heart River	30.407
- Donnelly	30.442
- House	16.630
Progas Limited	25.626
Societe quebecoise d'initiatives petrolieres (SOQUIP)	170.139
Sulpetro Limited	24.586
TransCanada PipeLines Limited	
- Average(1)	46.149
- Category A	46.674
- Category B1B2	46.836
- Category B1B3	47.492
- Category B1D2	42.216
- Category D1B2	28.563
- Category D1B3	29.906
- Category D1D2	26.482
- Category E	31.929
Westcoast Transmission Company	
- Husky Oil Ltd.	18.383
- Petrogas Processing Ltd. et al	19.174
Westcoast Transmission Company (Alberta) Limited	
- North	8.274
- Triassic E	.474

.../2

Section 15(3)(b) 33.000

Notes

* Calculated on a gross and dry heating value basis at 101.325 kpa (kilopascal) and $15^{o}C$.

Notice

The price adjustment for gas is $0.50/GJ
The Alberta Border Price is $2.633 66/GJ

(1) For purposes of sales within Alberta

DETERMINATION 84-03 (TCP)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

APPLICATION

By letters dated February 16, 1984 and February 20, 1984, TransCanada PipeLines Limited (TransCanada) applied to the Commission to include in its Alberta cost of service interest charges and stand-by fees related to the second closing of the Topgas Two program.

The application and Determination 83-09 (TCP) are attached hereto.

DECISION

The application is granted.

REASONS

The Commission considers that take or pay financing costs fall under the Natural Gas Pricing Agreement Regulation (A.R.119/82) as being ". . . considered just and reasonable by the Commission in respect of costs incurred by a person, whether or not the person is the original buyer, to finance payments made to or for the benefit of a producer in respect of gas not taken by the original buyer under a gas sales contract for which the producer was nevertheless entitled to be paid."

The Commission views this determination as an extension of Determination 83-09 (TCP) and would encourage delay of final closure of the Topgas Two program until the costs of TransCanada's financing, outside of the Topgas Two program, have become known to the producers concerned.

DATED this 28th day of February, 1984 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

PROVINCE OF ALBERTA

ALBERTA PETROLEUM MARKETING COMMISSION

APPLICATION TO INCLUDE IN TRANSCANADA'S ALBERTA COST OF SERVICE THE INTEREST COSTS OF TOPGAS TWO INC. ARISING IN RESPECT OF THE FINANCING OF TAKE OR PAY PAYMENTS TO BE MADE BY TOPGAS TWO INC. ON MARCH 1, 1984

I. Request

TransCanada Pipelines Limited ("TransCanada)" requests that the Alberta Petroleum Marketing Commission ("the Commission") determine that from March 1, 1984, until the end of the allocation period (as defined in the Topgas Two Agreement), it shall be just and reasonable to include and there shall be included in TransCanada's Alberta cost of service, interest at the rate of the Canadian Prime Rate (as defined in the Topgas Two Agreement) plus 7/8 of 1% in respect of the financing by Topgas Two of payments to be made March 1, 1984, by Topgas Two for gas available but not taken by TransCanada during the 1982/83 contract year.

TransCanada further requests that the Commission determine that it shall be just and reasonable to include and there shall be included in TransCanada's Alberta cost of service, additional financing costs necessitated by the second closing of the Topgas Two Program described below.

II. The Topgas Two Program

TransCanada, Topgas Holdings Limited ("Topgas"), Topgas Two, and

TransCanada's participating producers entered into an agreement, dated November 14, 1983, (the "Topgas Two Agreement") which provided for certain amendments to the 1982 allocation program as implemented through the agreements dated May 20, 1982, between TransCanada, Topgas and TransCanada's producers (the "Topgas Agreement"). The Topgas Two Agreement provided, among other things, that Topgas Two would make certain payments to TransCanada's producers in satisfaction of TransCanada's obligation to pay for gas available but not taken during the 1982/83 contract year. A copy of the Topgas Two Agreement was provided to the Commission as Exhibit "A" to TransCanada's application to the Commission dated November 16, 1983. The transactions contemplated under the Topgas Two Agreement were closed on December 30, 1983. As at January 30, 1984, Topgas Two payments to TransCanada's producers were outstanding in the amount of $274,475,558.90 for take or pay gas.

III. Second Closing of the Topgas Two Program

TransCanada, Topgas, and Topgas Two have agreed to a second Closing under the Topgas Two Program which will occur on March 1, 1984. This second Closing will be available to those producers who did not participate in the Topgas Two Closing which took place on December 30, 1983, but who may have received payment from TransCanada at that time for gas not taken by TransCanada during the 1982/83 contract year pursuant to the terms of the Topgas Agreement (such take or pay gas being referred to as "TransCanada Prepaid Gas").

Producers who intend to participate in the second Closing are required to execute and return to TransCanada, Topgas Two Agreements together with a short letter of agreement (the "Amending Agreement"), a copy of which is attached as Exhibit "A". The Amending Agreement provides for a closing on March 1, 1984 and authorizes Topgas Two to advance funds to the credit of the producer at that time. Additionally, the Amending Agreement provides for the return to TransCanada of those funds which TransCanada advanced to such producers on December 30, 1983, in respect of TransCanada Prepaid Gas.

At the date of this application, TransCanada has made outstanding payments in respect of 1982/83 TransCanada Prepaid Gas in the amount of $74,626,920.18 representing 36,408,833 gigajoules of prepaid gas. To the extent that, on the second Closing, those producers who were not included in the December 30 Closing choose to participate in the Topgas Two program, such TransCanada Prepaid Gas will cease to be outstanding on March 1, 1984 and, thereafter, there will be outstanding an equivalent amount of Topgas Two Prepaid Gas under the Topgas Two program which is additional to the Topgas Two Prepaid Gas which was outstanding as of December 31, 1983.

IV. Additional Financing Costs

In TransCanada's application to the Commission dated November 16, 1983, TransCanada requested the recovery through its Alberta cost of service of certain Financing and Administration costs asssociated with the implementation and administration of the Topgas Two Program. These costs,

described in detail on pages 13 through 15 of the said application, were submitted to the Commission as costs incurred to finance payments paid to producers by Topgas Two on December 30, 1983. As a result of the agreement between TransCanada, Topgas and Topgas Two to offer a second Closing under the Topgas Two Program, certain additional costs will be payable by TransCanada. TransCanada advises the Commission that the stand-by fee, described in the said application in paragraph (c) on page 14, will continue to be charged to Topgas Two during the period of December 31, 1983 to March 1, 1984. TransCanada does not expect the other Financing and Administration Costs described in the said Application to be altered as a result of the second Closing.

V. Conclusion

Accordingly, TransCanada respectfully requests that the Commission determine that:

(a) from March 1, 1984, until the end of the allocation period, there shall be included in TransCanada's Alberta cost of service, interest at the rate of the Canadian Prime Rate plus 7/8 of 1% per annum in respect of the financing by Topgas Two of payments to be made on March 1, 1984, by Topgas Two in respect of gas available but not taken by TransCanada during the 1982/83 contract year; and

(b) that there shall be included in TransCanada'a Alberta cost of service the additional financing costs, as described above, necessitated by the second closing of the Topgas Two Program.

All of which is respectfully submitted

TRANSCANADA PIPELINES LIMITED

per: ______________________

E. W. H. MALLABONE
Manager, Legal

Communications related to this Application should be directed to:

Mr. E. W. H. Mallabone
Manager, Legal
TransCanada PipeLines Ltd.
TransCanada PipeLines Tower
530 - 8th Avenue S.W.
P.O. Box 500, Station M
Calgary, Alberta
T2P 3V6

TransCanada PipeLines
TRANSCANADA PIPELINES TOWER 530 EIGHTH AVENUE S.W.
P.O. BOX 500 STATION M CALGARY CANADA T2P 3V6
(403) 269 5611

February 20, 1984

Alberta Petroleum Marketing Commission
1900 Bow Valley Square IV
250 - 6th Avenue S.W.
Calgary, Alberta
T2P 3H7

Attention: Mr. V. M. Thomas

Dear Sir:

Further to your request by letter dated February 17, 1984, for additional information in respect of TransCanada's application to the Commission dated February 16, 1984 (Docket number 84-13), TransCanada advises the Commission as follows:

1. From December 30, 1983 to January 19, 1984, the funds committed by the banking syndicate for the financing of additional take or pay payments by Topgas Two were $125 million, giving rise to a standby fee of $17,952.82. This amount committed was reduced to $85 million at TransCanada's request on January 19, 1984. From January 19, 1984 to February 29, 1984, TransCanada estimates a further standby fee of $24,000.

2. TransCanada proposes to include these standby fees in its Alberta cost of service in a manner consistent with the procedure proposed in its application dated November 16, 1983 (at p. 16) which was granted by the Commission in its Determination 83-09 (TCP).

3. The additional amount of the payments that Topgas Two will make on March 1, 1984 is limited by the $74.6 million outstanding for TransCanada Prepaid Gas. This amount, however, is subject to a possible adjustment to the payments made to producers by Topgas Two on the December 30, 1983 Closing by as much as $10 million. At the date of this letter and on the basis of TransCanada's observation of producer participation in the March 1 Closing, TransCanada anticipates that the additional amount to be paid out by Topgas Two on March 1 will be considerably less than $74.6 million.

4. TransCanada encloses herewith twelve copies of the Amending Agreement, which were to be attached to TransCanada's application of February 16, 1984.

Yours very truly,

E.W.H. Mallabone
Manager, Legal

EWH/ed
Encl.

RECEIVED
FEB 20 1984
ALBERTA PETROLEUM
MARKETING COMMISSION

1984-01-24

(hereinafter referred to as "Seller")

Gentlemen:

This will refer to the agreement dated May 20, 1982 among TransCanada PipeLines Limited ("TransCanada"), Topgas Holdings Limited ("Topgas") and Seller, as the same heretofore may have been amended (the "Original Agreement"). Unless otherwise provided herein, all terms defined in the Original Agreement are used herein as so defined.

Pursuant to the Original Agreement, TransCanada paid to Seller or Seller's agent on December 30, 1983 an amount in respect of TransCanada Prepaid Gas incurred in the 1982/83 contract year.

TransCanada, Topgas, Topgas Two Inc. ("Topgas Two") and certain sellers of gas to TransCanada have entered into agreements dated November 14, 1983 (the "Topgas Two Producer Agreements") which provide, inter alia, for payments by Topgas Two in respect of gas available but not taken by TransCanada during the 1982/83 contract year and which would otherwise have constituted TransCanada Prepaid Gas. For the purposes of this agreement, those Seller's Gas Purchase Contracts (as defined in Seller's Topgas Two Producer Agreement) in respect of which Topgas Two did not make a payment on December 30, 1983 and in respect of which each of the parties thereto have executed and delivered an agreement substantially similar to this agreement are referred to as "Additional Gas Purchase Contracts".

As certain parties to some or all of Seller's Gas Purchase Contracts (as defined in the Original Agreement) did not execute and deliver a Topgas Two Producer Agreement prior to December 30, 1983 but have now done so, Seller wishes to enter into this agreement for the purpose of substituting payments by Topgas Two for payments made by TransCanada on December 30, 1983 in respect of TransCanada Prepaid Gas for the 1982/83 contract year.

In consideration of Topgas and Topgas Two executing this agreement and any Topgas Two Producer Agreement which has not been previously executed and delivered and which amends any of Seller's Gas Purchase Contracts (as defined in the Original Agreement), the parties hereto agree as follows:

1. Seller hereby acknowledges that it or its agent received from TransCanada those payments set out in Exhibit "B" hereto in respect of TransCanada Prepaid Gas for the 1982/83 contract year incurred under each of the gas purchase contracts set forth in Exhibit "B".

2. Notwithstanding the provisions of paragraph 2A of Seller's Topgas Two Producer Agreement, the payment required to be made by Topgas Two with respect to each Additional Gas Purchase Contract shall be made on March 1, 1984 in lieu of December 30, 1983 as therein provided. On March 1, 1984 Seller shall refund to TransCanada the amount of the payments received from TransCanada on December 30, 1983 in respect of each Additional Gas Purchase contract by directing Topgas Two to pay to TransCanada the payments to be made by Topgas Two pursuant to paragraph 2A of Seller's Topgas Two Producer Agreement as amended by this Agreement and Seller hereby so directs.

3. Except for the purpose of determining for the period prior to March 1, 1984 the Alberta Cost of Service in respect of any Additional Gas Purchase Contract, upon receipt by TransCanada of the payments referred to in paragraph 2 hereof, TransCanada shall be deemed not to have incurred TransCanada Prepaid Gas in respect of the 1982/83 contract year in respect of any Additional Gas Purchase Contract and for all other purposes of Seller's Topgas Two Producer Agreement, Topgas Two Prepaid Gas (as defined in the Topgas Two Producer Agreement) under each Additional Gas Purchase Contract shall be deemed to have been outstanding as of December 31, 1983.

4. Except as otherwise expressly provided for herein, Seller's Topgas Two Producer Agreement is hereby confirmed.

TRANSCANADA PIPELINES LIMITED

Per: ______________________
Vice President

Per: ______________________ c/s
Assistant Secretary

Agreed and accepted the 1st day of March 1984

TOPGAS HOLDINGS LIMITED

Per: ______________________ c/s

TOPGAS TWO INC.

Per ______________________ c/s

Agreed and accepted by Seller the ________ day of __________, 1984.

SELLER (Print in Seller's Name)

____

Per: ______________________

Per: ______________________ c/s

DETERMINATION 83-09 (TCP)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

APPLICATION

By application dated November 16, 1983 TransCanada PipeLines Limited (TransCanada) requests approval to include in its Alberta cost of service costs of a program referred to as "Topgas Two". The application (without exhibits) is shown in Appendix "A" hereto.

The costs include interest on financing by Topgas Two of a maximum $400 million of take or pay payments and other costs for which TransCanada is committed to pay Topgas Two Inc.

The interest costs will be at the rate per annum of Canadian Prime Rate plus 7/8 of 1%. Canadian Prime Rate as defined in an exhibit to the application is:

> "... an annual rate of interest equal to the arithmetic average (rounded to the nearest one-thousandth of one per cent) of the rates of interest quoted or published by each of Canadian Imperial Bank of Commerce, Citibank Canada, Morgan Bank of Canada and the Royal Bank of Canada (the "Reference Banks") from time to time as being their respective prime rates of interest for Canadian dollar loans made in Canada, provided that if any of the Reference Banks fail to quote or publish a rate of interest as being its prime rate of interest for Canadian dollar loans made in Canada, such average shall be calculated as if such Reference Bank was not one of the Reference Banks."

Financing and administration costs associated with the development, organization and administration of the Topgas Two program for which TransCanada is required to pay Topgas Two Inc. are shown in Appendix "B". The cost estimates were provided by TransCanada at the Commission's request subsequent to the date of application.

DECISION

1. The application is granted.

2. TransCanada shall apply to the Commission for approval of its financing of outstanding take or pay payments that are not included in the Topgas Two program.

3. TransCanada shall in December, 1984 and in December of each year thereafter provide such information as may be required by the Commission to assess the prudency of contract management.

REASONS

The Commission considers that take or pay financing costs fall under the Natural Gas Pricing Agreement Amendment Regulation (A.R.119/82) as being "...considered just and reasonable by the Commission in respect of costs incurred by a person, whether or not the person is the original buyer, to finance payments made to or for the benefit of a producer in respect of gas not taken by the original buyer under a gas sales contract for which the producer was nevertheless entitled to be paid."

The Commission had expected that the Topgas program of last year which addressed the take or pay levels and TransCanada's apparent inability to sustain the magnitude of the financing requirements of take or pay payments would have eliminated the necessity for similar programs in the future. However, TransCanada's markets have deteriorated more than expected and additional take or pay liabilities have been incurred. The Topgas Two program allows each producer to assess the benefits of participation and to accept or reject the proposal. Therefore, in arriving at the decision in this determination, the Commission has not considered whether the Topgas Two program is the only feasible method of financing take or pay payments. Furthermore, in view of the necessity of producer agreement the Commission sees no reason to dispute its appropriateness.

TransCanada has filed an application requesting separate Alberta costs of service in order to apportion take or pay financing costs among producers depending on the extent of their participation in the Topgas and Topgas Two programs. The Commission recognizes the necessity of separate Alberta costs of service in order to allocate fairly financing costs among different categories of gas purchase contracts.

In reviewing the circumstances giving rise to TransCanada's take or pay obligation for the contract year ended October 31, 1983, the Commission is satisfied the situation did not result from imprudent actions of TransCanada. The Commission has also assessed and is satisfied there is continued necessity of financing for take or pay payments previously authorized by the Commission.

DATED this 9th day of December, 1983 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

PROVINCE OF ALBERTA

ALBERTA PETROLEUM MARKETING COMMISSION

APPLICATION FOR APPROVAL

TO INCLUDE

THIRD PARTY TAKE OR PAY INTEREST COSTS

AND TRANSCANADA COSTS ARISING UNDER

THE TOPGAS TWO PROGRAM IN THE

ALBERTA COST OF SERVICE

OF TRANSCANADA PIPELINES LIMITED

A. REQUEST

TransCanada PipeLines Limited ("TransCanada") requests that the Alberta Petroleum Marketing Commission ("the Commission") determine that it shall be just and reasonable to include and there shall be included in TransCanada's Alberta cost of service:

(a) interest at a rate per annum equal to the Canadian Prime Rate (as defined in the Topgas Two Agreement referred to below) plus 7/8 of 1% payable by Topgas Two Inc. ("Topgas Two") on monies borrowed by Topgas Two to finance payments to be made by Topgas Two to or for the benefit of Alberta gas producers in respect of gas not taken by TransCanada in the 1982/83 contract year but for which such producers were nevertheless entitled to be paid under TransCanada's gas purchase contracts as amended by an agreement between TransCanada, Topgas Holdings Limited ("Topgas") and TransCanada's producers dated May 20, 1982 (the "Original Agreement"), during the period commencing on

December 30, 1983 and continuing until the end of the allocation period as defined in the "Topgas Two Agreement" (as defined below), a copy of which is attached hereto as Exhibit "A".

(b) all costs for which TransCanada will become liable as a result of the organization, implementation and ongoing administration of the Topgas Two program (as defined below).

B. TAKE OR PAY STATUS

(a) The Topgas Program

In October of 1982, TransCanada and Topgas implemented a program (the "Topgas program") under which Topgas paid TransCanada's producers the amount of TransCanada's obligation to make take or pay payments for prepaid gas incurred during the 1981/82 contract year and for those volumes of gas up to the minimum annual obligation under each particular gas purchase contract, for which TransCanada was not required to pay as a result of TransCanada's 1980/81 and 1981/82 allocation program. In addition, Topgas advanced funds to TransCanada's producers equal to the take or pay monies advanced by TransCanada to producers prior to the 1981/82 contract year. The Topgas program and TransCanada's take or pay status prior to October, 1982 were described to the Commission in detail in TransCanada's application dated June 18, 1982.

As at September 30, 1983, take or pay gas outstanding under the Original Agreement ("Topgas Prepaid Gas") was as follows:

TOPGAS PREPAID GAS BALANCES
SEPTEMBER 30, 1983

Contract Year Ended Oct. 31	Take or Pay Recovered and Returned Since December 31, 1982 Quantity (GJ)	Amount ($)	Take or Pay Outstanding Quantity (GJ)	Amount ($)
1977			6 844 718	7 008 858
1978	3 818 889	4 423 151.93	108 052 055	125 150 103
1979	2 533 604	3 226 721.46	156 140 448	198 855 791
1980	1 921 995	3 072 673.49	289 133 772	462 235 269
1981	928 014	1 214 918.21	474 303 791	621 348 334
1982	8 674 184	13 710 241.71	562 336 824	888 818 337
	17 876 686	25 647 706.80	1 596 811 608	2 303 416 692

(b) Present Situation

Under the Original Agreement, TransCanada is presently obligated, during the period commencing on November 1, 1982 and ending on the date that all Topgas Prepaid Gas is recovered, to take or pay for gas at 60% of its 1981/82 annual obligation under the Seller's Gas Purchase Contracts as defined in the Original Agreement or 75% of a particular year's obligation, whichever is lesser.

The Topgas program was implemented in October, 1982. During the 1982/83 contract year TransCanada has experienced sales of natural gas at the lowest annual level since 1973. The combination of recessionary conditions, increasing natural gas prices, energy conservation, unseasonably warm weather and the prevailing uncertainty in respect of the deregulation

of U.S. gas markets has resulted in a significant decline in natural gas consumption. In addition, because of the high levels of drilling activity in the late 1970's and early 1980's there is at present a substantial surplus of natural gas available for delivery in both Canada and the United States.

At the outset of the Topgas program in March of 1982, TransCanada's projections of average weekly deliveries at the Alberta/Saskatchewan border were made during a time when TransCanada's winter requirements were at the highest level in its history. At that time, TransCanada projected that its future load pattern would be similar to that which had occurred in the immediate past, and it was expected that, during the next year, TransCanada's takes would be at a higher level than had occurred in 1981.

Beginning in April, 1982, and throughout the summer of 1982, TransCanada's requirements declined significantly below the normal load pattern which TransCanada had anticipated. Since the summer of 1982, market demand has continued at unexpectedly low levels. Throughout the 1982/83 winter season, TransCanada's takes at the Alberta/Saskatchewan border have been lower than during any similar period in the past five years. Summer deliveries for 1983 were such that TransCanada's total market of 1040 Bcf for the 1982/83 contract year was the lowest annual requirement in the last decade.

This market decline has prevented TransCanada from taking gas under its allocable gas purchase contracts at the minimum take or pay level required by the Original Agreement. As a result, TransCanada has incurred an obligation to pay some of its sellers of gas for take or pay gas with respect to the 1982/83 contract year. It is estimated that TransCanada's average take under it's allocable contracts will be approximately 47% of TransCanada's minimum annual obligations under all of its allocable contracts for the 1982/83 contract year. TransCanada estimates the obligation for gas not taken during the 1982/83 contract year under TransCanada's allocable gas purchase contracts as amended by the Original Agreement, will be an amount not exceeding 400 million dollars. A more detailed review of these matters is attached hereto as Exhibit "B" ("Market Supply Update").

C. PRUDENCY

TransCanada continues to act in a prudent and responsible manner in its efforts to minimize its take or pay volumes, its prepayments and its related carrying charges and to allocate its market equitably among its producers.

The following major actions have been taken during the current and prior years and are in place to ensure the achievement of the aforementioned objectives:

(1) Allocation

At the time of the implementation of the Topgas program which replaced the earlier allocation program, TransCanada successfully brought over in excess of 99% of its gas purchase contracts by volume within the allocation scheme under the Original Agreement. Producers who entered into the Topgas program received payment from Topgas for the additional volumes arising under the allocation program for the 1980/81 contract year, payment from Topgas for all take or pay gas outstanding as of December 31, 1981 as well as payment for the full amount of take or pay gas incurred in the 1981/82 contract year based on 100% of obligation. Commencing on November 1, 1982, TransCanada has equitably allocated its annual market available for allocation to its gas purchase contracts.

(2) Accelerated Recovery

During the 1982/83 contract year, TransCanada has diligently exercised its rights under paragraph 19 of the Original Agreement to accelerate recovery in respect of those contracts where recovery of Topgas Prepaid Gas cannot be otherwise achieved. As a result of notices under paragraph 19, 55 gas purchase contracts are now subject to agreements which accelerate the recovery of Topgas Prepaid Gas. Producers have returned or will return Topgas Prepaid monies, in respect of 15 such contracts, and negotiations continue under paragraph 19 with respect to 69 of these contracts.

TransCanada will continue to diligently monitor deliverability performance for gas contracts to ensure complete recovery of Topgas Prepaid Gas under all contracts.

(3) Marketing

TransCanada continues to seek increased export markets for Alberta gas. TransCanada has recently concluded Memmorandums of Understanding with Michigan Wisconsin PipeLine Company and Great Lakes Gas Transmission Company, two of its U.S. Buyers, which address the take or pay deficiencies incurred under TransCanada's sales contracts in the 1982/83 contract year and expected in the succeeding two contract years. These understandings introduce the concept whereby the Buyer will be required to take and pay for 50% of its annual obligation. If the Buyer fails to take such volumes, payment will be made in any event at the export border price without any right of make-up. TransCanada expects that such a requirement will substantially increase TransCanada's export sales in the 1983/84 contract year.

TransCanada continues to actively seek increased gas sales throughout the market areas in Canada to which TransCanada has access. During the 1982/83 contract year, TransCanada has participated in an extensive advertising program in order to promote the consumption of natural gas in Eastern Canada.

(4) Gas Supply

TransCanada continues to evaluate its contracted reserves and associated deliverability to ensure that it prudently exercises its rights to reduce its exposure to future take or pay obligations.

In accordance with the Original Agreement, TransCanada did not enter into any new gas purchase contracts during the 1982/83 contract year other than solution gas contracts.

During 1983, TransCanada, Consolidated Natural Gas Limited ("Consolidated"), Topcon Holdings (Alberta) Limited and Consolidated's producers successfully negotiated an arrangement which brought TransCanada's Consolidated gas supply within the TransCanada allocation program. TransCanada thereby reduced the level of its take or pay obligation to Consolidated.

Despite TransCanada's ongoing efforts to overcome the supply/demand imbalance, TransCanada has incurred a take or pay obligation for the 1982/83 contract year. TransCanada has determined that the most cost-effective way of financing such payments is through a Topgas-like arrangement. Accordingly, TransCanada has developed an arrangement with Topgas Two (the "Topgas Two program") which it has submitted to the producing industry.

D. THE TOPGAS TWO PROGRAM

The Topgas Two program will be implemented by an amendment to the Original Agreement and will be entered into among such participating producers, TransCanada, Topgas and Topgas Two. The program will apply only to those gas purchase contracts that are amended by the Topgas Two Agreement.

The Topgas Two program may be summarized as follows:

(i) On December 30, 1983, Topgas Two will pay to each participating producer in respect of all gas purchase contracts amended by the Topgas Two Agreement, the take or pay payment for the 1982/83 contract year which TransCanada is otherwise obligated to make under the Original Agreement.

(ii) Producers who have entered into the Topgas Two Agreement will have the option of waiving their right to payment from Topgas Two.

(iii) For the 1983/84 contract year, the level, below which TransCanada is required to make take or pay payments, is reduced from the existing 60% of the 1981/82 minimum annual obligation under each contract, to 50% of the 1981/82 minimum annual obligation under

each such contract. In each subsequent year of the allocation period, this take or pay floor is to be calculated as the average of the two preceding years' market available for allocation, expressed as a percentage of the respective year's aggregate minimum annual obligations under all allocable gas purchase contracts, less five percentage points. This formula is subject to the proviso that the minimum required take or pay level will not be less than 50% nor exceed 60% of the 1981/82 minimum annual obligation. Under the Topgas program TransCanada is only entitled to recover take or pay gas which it incurs under a particular contract (defined as "TransCanada Prepaid Gas") after all Topgas Prepaid Gas has been recovered by Topgas in respect of such contract.

(iv) Under the Topgas program and commencing with the 1984/85 contract year, Topgas Prepaid Gas will be recovered as a portion of the producer's annual deliveries, which portion will be the volume of gas having a heat content equal to at least 10% of the Topgas Prepaid Gas outstanding as of December 31, 1982. TransCanada would recover 1/4 of this portion in each of the first four months of the contract year. If TransCanada's markets substantially increase, the rate of recovery of Topgas Prepaid Gas would also increase.

Under the Topgas Two Program and commencing with the 1984/85 contract year, Topgas Prepaid Gas and gas paid for by Topgas Two ("Topgas Two Prepaid Gas") will be recovered as a portion of the producer's annual deliveries, which portion will be an amount of gas having a heat content equal to at least 10% of the Topgas Prepaid Gas oustanding as of December 31, 1982 and at least 10% of the Topgas Two Prepaid Gas outstanding as of December 31, 1983. TransCanada will recover <u>1/5</u> of this portion in each of the first <u>five</u> months of the contract year. In allowing Topgas Two to make payments for the take or pay gas incurred by TransCanada in the 1982/83 contract year and to recover such gas as Topgas Two Prepaid Gas concurrently with Topgas Prepaid Gas, the Topgas Two Agreement varies the Original Agreement insofar as TransCanada Prepaid Gas will no longer be recovered after Topgas Prepaid Gas.

(v) The Topgas Two Agreement amends the max. day relief provision of the Original Agreement by providing that, during the 1983/84 contract year, a producer will not be required, under an allocable gas purchase contract, to deliver gas on a given day in excess of 65% of the maximum daily volume under the contract, and during each subsequent contract year of the allocation period, a

producer will be required, under an allocable gas purchase contract, to deliver gas on a given day at no less than 75% of the maximum daily volume under the contract. This amendment prevents max. day relief from falling to unrealistically low levels which interfere with equitable allocation and endanger full industry response to future increases in market demand.

(vi) Apart from amending the Original Agreement to accomodate the foregoing, the Topgas Two Agreement restates and modifies the terms of the Original Agreement and varies or modifies the Original Agreement.

The obligations of Topgas Two and TransCanada are subject to the conditions that there be a satisfactory assurance that it is appropriate for TransCanada to include and equitably apportion in its Alberta cost of service the interest associated with the payments to be made by Topgas Two, that sufficient sellers of gas execute and deliver the Topgas Two Agreement, and that Topgas be authorized by its lenders to enter into the Topgas Two Agreement.

The foregoing conditions must be satisfied on or before December 16, 1983 unless waived by all of Topgas, Topgas Two and TransCanada. TransCanada has submitted to its producers the Topgas Two Agreement and has requested of its producers that they execute and return the Agreement by December 15, 1983.

E Financing Agreement

TransCanada and Topgas Two will enter into a Financing Agreement (the "Topgas Two Financing Agreement") which among other things will provide for a TransCanada indemnity of Topgas Two and payment by TransCanada of the various initial and ongoing expenses of Topgas Two in undertaking the Topgas Two program (the "financing and administration costs").

Limited Indemnity

TransCanada will indemnify Topgas Two to a maximum of 55 million dollars in respect of damages suffered by Topgas Two which may be suffered by Topgas Two under the Topgas Two program. This indemnity is in addition to the 300 million dollar indemnity given by TransCanada to Topgas under the Topgas program.

Financing and Administration Costs

TransCanada is liable to reimburse Topgas Two the fees and expenses normally associated with a major financing of this nature and proposes that these financing and administration costs be included in TransCanada's Alberta cost of service. These costs are:

(a) an up-front fee charged to Topgas Two by the managing bank and in respect of the monies committed to Topgas Two for the purpose of payments to be made under the Topgas Two Agreement. The up-front fee will be calculated as 1/2 of 1% of the monies committed to be advanced to Topgas Two for distribution among TransCanada's producers.

(b) a co-ordinator's fee, calculated as 1/20 of 1% of the monies committed to be advanced by Topgas Two, to be paid to the co-ordinators of the Topgas Two syndicate who undertook the development and organization of the Topgas Two program

(c) a stand-by fee, charged to Topgas Two in respect of funds committed by the banks to Topgas Two but undrawn. TransCanada anticipates that this stand-by fee will be calculated as ¼ of 1% per annum from the date or dates of such commitment until the date or dates that such money is drawn by Topgas Two.

(d) all other reasonable fees and disbursements payable by Topgas Two or the co-ordinators of the Topgas Two syndicate associated with the development and organization of the Topgas Two program including legal costs, engineering costscosts and printing costs.

(e) an annual fee in the amount of $15,000 per annum to be paid by Topgas Two to the Canadian Imperial Bank of Commerce for the ongoing administration of Topgas Two program together with expenses and disbursements related thereto.

(f) two annual agency fees each in the amount of $10,000 and payable to the Canadian Imperial Bank of Commerce and the Morgan Bank of Canada as agents for the lenders to Topgas Two.

F. CONCLUSION

For the foregoing reasons, TransCanada respectfully requests that the Commission determine:

(1) that it shall be just and reasonable to include and there shall be included in TransCanada's Alberta cost of service, interest at a rate per annum equal to the Canadian Prime Rate, as defined in the Topgas Two Agreement, plus 7/8 of 1% payable by Topgas Two on monies borrowed by Topgas Two up to a maximum of 400 million dollars to finance payments made by it to or for the benefit of Alberta gas producers;

(2) that the inclusion of such interest costs may commence on December 30, 1983 and continue thereafter until all Topgas Two Prepaid Gas is recovered;

(3) that there shall be included in TransCanada's Alberta cost of service the financing and administration costs associated with the development, organization and ongoing administration of the Topgas Two program; and

(4) that the financing and administration costs, other than the ongoing administration fees and expenses, be capitalized and amortized monthly on a straight-line basis over the term of the Topgas Two program, and that such costs be included in TransCanada's Alberta cost of service commencing in the month of January, 1984 and continuing thereafter until such amounts are fully recovered.

DATED at the City of Calgary, in the Province of Alberta, this 16th day of November 1983.

All of which is respectfully submitted,

TRANSCANADA PIPELINES LIMITED

per: ______________________
E.W.H. MALLABONE
Manager, Legal

Communications related to this
Application should be directed to

Mr. E.W.H. Mallabone
Manager, Legal
TransCanada PipeLines Limited
TransCanada PipeLines Tower
530 - 8th Avenue S.W.
P.O. Box 500
Station M
Calgary, Alberta
T2P 3V6

SCHEDULE 1

TransCanada PipeLines - Topgas Two

AGREEMENT	DESCRIPTION	ESTIMATED AMOUNT ($000)
One Time Costs		
TransCanada - Topgas Two	Stand-by fee 1/4 of 1% of undrawn portion to Dec. 30, 1983.	250
	TransCanada is liable for payment to all lenders through Topgas Two.	
	Management fee (Up-front fee) 1/2 of 1%	2,000
	TransCanada is liable for payment to lenders through Topgas Two.	
Canada - Co-ordinating	Co-ordinating Managers fee 1/20 of 1%.	200
	Total estimated expenses (legal, engineering, other)	1,300
	TransCanada is liable for payment to the co-ordinating banks.	
	Total Estimated One Time Costs	**$3,750**
nual Costs		
	Administration and Agency fees.	35
	Topgas Two estimated operating and audit costs.	50
	Total Estimated Annual Costs	**85**

ML. 1. 523

PETROLEUM MARKETING COMMISSION

403/262-8808
Telex: 03-821978
1900, 250 - 6th Avenue S.W.
Calgary, Alberta, Canada
T2P 3H7

March 30, 1984

INFORMATION BULLETIN RE ALBERTA COST OF SERVICE

The Alberta Cost of Service Information Bulletin for the month of February, 1984 is attached.

The Information Bulletin consists of:

1. Copies of any special Orders or Determinations issued by the Commission during the month with respect to Alberta Cost of Service, and notice of any Statements of Objection which have been received during the month; and

2. Alberta Cost of Service Determinations for the month.

In the case of gas intended to be removed from Alberta, the cost of service determined under Section 11(1), 15(3)(a) and 15(5)(b)(i) of the Natural Gas Pricing Agreement Act for each month is based on estimated figures for that month, adjusted to allow for differences between the estimated and actual figures for the previous month.

In the case of gas intended for consumption within Alberta, the amount estimated as cost of service under Sections 11(2)(a)(ii) and 15(3)(b)(i) of the Act were made under the Commission's general directive for the Alberta cost of service.

All determinations are on gross or higher heating value on a dry basis at 15°C and an absolute pressure of 101.325 kPa (kilopascal).

Yours very truly,
ALBERTA PETROLEUM MARKETING COMMISSION

D. L. Willis
Vice-Chairman

Attachment

INFORMATION BULLETIN
ALBERTA COST OF SERVICE DETERMINATION
PURSUANT TO THE NATURAL GAS PRICING AGREEMENT ACT
MONTH OF FEBRUARY, 1984

Section 15(3)(a)	Cents Per Gigajoule (GJ)*
Alberta and Southern Gas Co. Ltd.	
- Category A	49.148
- Category B	44.686
- Category E	N/A
Canadian Montana Pipe Line Company	48.977
Canadian Montana Gas Company Limited	48.974
Consolidated Natural Gas Limited	35.938
ICG Resources Ltd.	36.418
Many Islands Pipe Line (Canada) Limited	
- Purchased Gas	17.572
- North Sibbald (Agent)	3.176
- Saddle Lake	20.360
- Esther	11.965
Pan-Alberta Gas Ltd.	
- Basic	26.001
- Delivery Points - Joarcam	39.263
- Heart River	28.370
- Windy	64.236
- Lloydminster "B"	50.715
- Blue Jay	2.941
- Bear River	22.238
Progas Limited	25.316
Societe quebecoise d'initiatives petrolieres (SOQUIP)	67.275
Sulpetro Limited	25.346
TransCanada PipeLines Limited	
- Average(1)	52.218
- Category A	52.907
- Category B1B2	52.508
- Category B1B3	53.784
- Category B1D2	54.059
- Category D1B2	31.784
- Category D1B3	33.043
- Category D1D2	29.023
- Category E	34.987
Westcoast Transmission Company	
- Husky Oil Ltd.	21.967
- Petrogas Processing Ltd. et al	21.528
Westcoast Transmission Company (Alberta) Limited	
- North	58.841
- Triassic E	.474

.../2

Section 15(3)(b) 33.000

Notes

* Calculated on a gross and dry heating value basis at 101.325 kpa (kilopascal) and 15^{o}C.

Notice

The price adjustment for gas is $0.43/GJ
The Alberta Border Price is $2.790 01/GJ

(1) For purposes of sales within Alberta

DETERMINATION 84-05
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

REVIEW OF STATEMENT OF OBJECTION

On January 24, 1984, Cabre Exploration Ltd. and Petromark Minerals Ltd. (herein called the "Applicants") filed a statement of objection to the November 1983, Alberta cost of service Determination for TransCanada PipeLines Limited (herein called "TransCanada"). They contend that a certain gas purchase contract should be included in Category D rather than Category B. The statement of objection is attached as Appendix "A".

The Commission elected to review the statement of objection and directed the Applicants to place a notice of the objection in two consecutive issues of "The Herald" in Calgary and "The Journal" in Edmonton, on or before February 11, 1984 and to serve a copy on the Canadian Petroleum Association and Independent Petroleum Association of Canada on or before February 8, 1983.

TransCanada filed a submission with respect to the Applicants' statement of objection. The submission is attached as Appendix "B".

DECISION:

The gas purchase contract is not eligible for inclusion in Category D.

REASONS:

The issue in the statement of objection is whether the Applicants should share take or pay financing costs through Alberta cost of service in spite of the fact that they have not received take or pay payments. The Applicants seek to have their gas purchase contract included in Category D and therefore bear no interest costs.

Without the regulated pricing system imposed by the Natural Gas Pricing Agreement Act all costs related to gas purchases beyond the field delivery points, including costs related to take or pay payments, would be borne by gas buyers. The buyers would need pricing flexibility to ensure a spread between buying and selling prices at least sufficient to recover the costs of doing business. Pricing regulation removed all pricing flexibility for buyers of gas purchased for removal from Alberta. It also took away from buyers the opportunity to adjust or negotiate selling prices to increase volumes of sales to avoid take or pay liabilities.

In recognition of the inflexible position of buyers under regulated pricing, the Act allows the buyers to recover certain costs out of the Alberta border price for gas being taken. The Act gives the responsibility for determining Alberta cost of service to the Commission and in Determination 77-15 dated September 29, 1977, it was ruled that take or pay financing costs were costs referred to in section 2(1)(a) of the Act as "attributable to the acquisition of the gas by the original buyer." Therefore, the costs were eligible for recovery through Alberta cost of service. This ruling was upheld by the Public Utilities Board on appeal.

One of the main reasons why the financing costs of take or pay payments must be assessed against gas currently purchased by a buyer is that if it were established that the financing costs should apply only to the gas paid for but not taken, it would necessarily follow that those costs could not be recovered by the buyer until the buyer purchased the gas i.e. make-up gas. Therefore recovery of those costs would be limited to periods of make-up. That situation would simply not be workable or financeable.

The Commission has considered take or pay financing costs to be current costs for purposes of Alberta cost of service without regard as to when the take or pay payments were made or to whom they were made. As current costs they are recoverable out of the Alberta border price of all gas taken by a buyer monthly. Therefore until 1982 when Determination 82-10 (TCP) was issued prescribing a multi-tiered Alberta cost of service for TransCanada a single cost of service for TransCanada's purchases was in place and all gas purchased in a month bore the costs of financing take or pay payments. This was in accordance with Section 2(2) of the Act which provides as follows:

"(2) Subject to section 8, the Commission shall determine the Alberta cost of service for an original buyer or (sic) gas intended to be removed from Alberta that shall, unless otherwise ordered by the Commission, apply to all gas purchased in the month by that person as an original buyer."

(Section 8 refers to appeals to the Public Utilities Board)

The multi-tiered Alberta cost of service instituted by Determination 82-10 (TCP) and later replaced by Determination 82-14 (TCP) was considered by the Commission to be justified by the Topgas program which resulted in different financing arrangements with respect to take or pay payments made to participants and non-participants of the program. Topgas also resulted in assured recovery of take or pay payments made to the participants without increasing their share of market during the period of recovery. However, with the exception of Category D, the implementation of multi-tiers did not cause the Commission to deviate from the view that all gas being taken should bear the financing costs of payments made for gas not taken.

It is obvious that TransCanada cannot take delivery of more gas than it can market. Take or pay contracts give TransCanada the flexibility to match a restricted market demand with its supply commitments and the decision whether to take or pay will ordinarily be dictated by this matching process unless prudent contract management would warrant otherwise in order to avoid losing the opportunity to recover outstanding take or pay payments.

The Commission does not consider it relevant to compare the benefits of delivering gas for sale with the benefits to producers of receiving take or pay payments. It is not the producer who can choose whether the buyer will take or pay. The producer also lacks control over the timing of deliveries that may be required by the buyer to secure repayment of the take or pay payments except as provided in the Topgas program.

Without the multi-tier categorization occasioned by the Topgas program the Applicants' gas sales would have borne the financing costs of all take or pay payments made by TransCanada regardless of the amount of take or pay payments outstanding under the Applicants' gas purchase contract. The Commission fails to see justification for complaint as to inclusion of their gas purchase contract in Category B by virtue of the Applicants' participation in the Topgas program. Under the Topgas program the Applicants'

production will be prorated and bear a proportionate share of financing costs of all take or pay payments outstanding under the contracts in Category B. The Commission observes that the Applicants' prorated share will be the same percentage as other contracts under which gas will be delivered in repayment of take or pay payments. The concession, made by Category B producers having take or pay payments, to repay take or pay payments out of all TransCanada's prorated production is highly useful to TransCanada in the management of its supply commitments and of ultimate benefit to producers in reduced take or pay costs and supply commitments.

The Applicants seek to have their contract included in Category D. Their contract is not eligible for Category D because they cannot reduce the level of outstanding take or pay payments. Category D was established for Topgas participation for the limited purpose, perhaps misguided, of inducing a voluntary reduction in the amount of take or pay payments outstanding under Categories B and C contracts. The Commission does not consider it appropriate to extend the limits of eligibility for Category D and in view of the very minor success in inducing voluntary reductions, it has asked TransCanada for a submission on the merits of continuing to allow entry into Category D after October 31, 1984.

DATED THIS 23rd day of March, 1984, at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

APPENDIX "A"

IN THE MATTER of the Natural Gas Pricing Agreement Act and the Regulations thereunder

AND IN THE MATTER of the Alberta Cost of Service Determination for the month of November, 1983

STATEMENT OF OBJECTION

CABRE EXPLORATION LTD. ("Cabre") and PETROMARK MINERALS LTD. ("Petromark") hereby file a Statement of Objection pursuant to Section 6 of the Natural Gas Pricing Agreement Regulations (Alberta Regulation 127/77, as amended) made pursuant to the Natural Gas Pricing Agreement Act, R.S.A. 1975, c.38, as amended, with respect to the Alberta Cost of Service Determination made by the Alberta Petroleum Marketing Commission (the "Commission") for the month of November, 1983 (the "Determination").

Cabre and Petromark ("the Producers") are parties to a Gas Purchase Contract dated September 7, 1977 with TransCanada Pipelines Limited ("TCPL"), as amended ("the Contract"). Gas Sales from the Strome Area of Alberta (Township 44, Range 16, W4M) commenced pursuant to the Contract in July, 1983. There have been no payments made to the Producers for take-or-pay gas, as evidenced by the Affidavits set forth in Exhibit "A" attached hereto, either by TCPL or Topgas Holdings Limited ("Topgas"). In fact, as the first contract year does not end until October 31, 1984, potential liability for "take-or-pay" cannot be determined prior to such date.

The Producers object that the cost of service allocated to gas sold pursuant to the Contract during November, 1983 was 48.326 cents per gigajoule, which is the cost of service established for Category B TCPL contracts pursuant to the Determination. The Producers understand that in APMC Determination 82-10, Category B was intended to include TCPL contracts pursuant to which payments for outstanding take or pay gas had been made which contracts should properly attract, as a component of the Alberta cost of service, a proportionate share of Topgas and TCPL interest costs in respect to the payments made. In Determination 82-14, the APMC stated in Paragraph 4 of its Decision:

> "4. Category D shall consist of the gas purchase contracts amended by the Topgas or Option Agreement under which producers have repaid take or pay advances in full after October 5, 1982.
>
> No take or pay carrying costs shall be assessed to Category D."

As the Contract has been amended by the Topgas or Option Agreement therein referred to and as the Producers have received no payments for take or pay gas thereunder, nor are such payments likely to be made in the near future, the Producers submit that the Contract should properly be included within Category D and that the cost of service allocated during November, 1983 should be 26.150 cents per gigajoule rather than 48.326 cents per gigajoule which was allocated. The Producers understand that if they had

received payments for take or pay gas pursuant to the Contract and had repaid such amounts, the Contract would automatically be included within Category D. The Producers submit that the effect of repayment of payments made for take or pay gas is the same as having received no such payments and that if no take or pay carrying costs are to be assessed in respect of the former case, such costs should not be assessed in the latter case. In this regard we refer to the following statement which is contained in the second paragraph of the Reasons within APMC Determination 82-08:

> "It is recognized that a significant inequity results if producers which elect to receive reduced take or pay payments bear a portion of the higher carrying costs associated with payments made to those producers which receive the full payments. To alleviate this inequity separate Alberta costs of service are appropriate."

The Producers submit that this statement is applicable to the assessment of take or pay carrying costs in respect to the Contract as no payments were made pursuant to the Contract for which such costs were incurred.

Accordingly, the Producers request that the Contract be included within Category D and that appropriate adjustments be made so that the cost of service allocated to 438.4 10^3m^3 of gas sold pursuant to the Contract during November, 1983 is 25.150 cents per gigajoule rather than 48.326 cents per gigajoule and that

all sold pursuant to the Contract during November, 1983 is 25.150 cents per gigajoule rather than 48.326 cents per gigajoule and that all allocations of cost of service to the Contract thereafter be those determined in respect to contracts within Category D.

DATED at the City of Calgary this 24th day of January, 1984.

Respectfully Submitted,

H.R. Ward
Counsel for the Producers

The Producers address for all
purposes hereunder is as follows:

Burstall & Company
1200, 540 - 5th Avenue S.W.
(as of February 6, 1984
2100, 801 - 6th Avenue S.W.)
Calgary, Alberta

Attention: H.R. Ward

EXHIBIT "A"

AFFIDAVIT

CANADA)
)
PROVINCE OF ALBERTA)
)
TO WIT:)

I, ROBERT W. MACDONALD, of the City of Calgary, in the Province of Alberta, MAKE OATH AND SAY:

1. That I am the Senior Vice-President of Petromark Minerals, Ltd. ("Petromark"), a corporation registered to do business in the Province of Alberta.

2. That Petromark is a party to a Gas Purchase Contract with Cabre Exploration Ltd. and TransCanada PipeLines Limited dated September 7, 1977, as amended, and that as of the date hereof, Petromark has received no payments pursuant to such contract for gas not taken pursuant thereto.

SWORN BEFORE me at the City of Calgary, in the Province of Alberta, this 23 day of January, A.D. 1984)

Commissioner for Oaths in and for the Province of Alberta)
SYLVIA SEMENIUK
MY APPOINTMENT
EXPIRES AUG. 11. 1986

ROBERT W. MACDONALD

Exhibit "A"

AFFIDAVIT

CANADA)
PROVINCE OF ALBERTA)
TO WIT:)

I, HARRY B. WHEELER, of the City of Calgary, in the Province of Alberta, MAKE OATH AND SAY:

1. That I am the President of Cabre Exploration Ltd. ("Cabre"), a corporation registered to do business in the Province of Alberta.

2. That Cabre is a party to a Gas Purchase Contract with Petromark Minerals Ltd. and TransCanada Pipelines Limited dated September 7, 1977, as amended, and that as of the date hereof, Cabre has received no payments pursuant to such contract for gas not taken pursuant thereto.

SWORN BEFORE me at the City of Calgary, in the Province of Alberta, this 23 day of January, A.D. 1984

D. Mody

Commissioner for Oaths in and for the Province of Alberta

DEBRA JANET MODY
My Commission Expires
August 1, 1984

HARRY B. WHEELER

APPENDIX "B"

IN THE MATTER of the Natural Gas Pricing Agreement Act and the Regulations thereunder;

AND IN THE MATTER of the Alberta Cost of Service Determination for the month of November, 1983;

AND IN THE MATTER of the Statement of Objection dated January 24, 1984 filed with the Alberta Petroleum Marketing Commission by CABRE EXPLORATIONS LTD. and PETROMARK MINERALS LTD.

SUBMISSION OF TRANSCANADA PIPELINES LIMITED

IN THE MATTER of the Natural Gas Pricing Agreement Act and the Regulations thereunder;

AND IN THE MATTER of the Alberta Cost of Service Determination for the month of November, 1983;

AND IN THE MATTER of the Statement of Objection dated January 24, 1984 filed with the Alberta Petroleum Marketing Commission (the "Commission") by CABRE EXPLORATIONS LTD. ("Cabre") and PETROMARK MINERALS LTD. ("Petromark")

SUBMISSION OF TRANSCANADA PIPELINES LIMITED

Pursuant to Section 6(5) of the Natural Gas Pricing Agreement Regulations (Alberta Regulation 127/77, as amended), TransCanada responds to the Statement of Objection filed by Cabre and Petromark with respect to the Determination by the Commission of TransCanada's Alberta cost of service for the month of November, 1983, as follows.

TransCanada confirms that Cabre and Petromark (the "Sellers") are parties to a Gas Purchase Contract with TransCanada, dated September 7, 1977, as amended ("Sellers' Contract") and that gas sales under Sellers' Contract commenced in July of 1983. TransCanada advises the Commission that Sellers' Contract is a Seller's Gas Purchase Contract under the agreement dated May 20, 1982 between TransCanada, Topgas Holdings Limited ("Topgas") and Sellers ("Sellers' Topgas Agreement"). As, however, deliveries under Sellers' Contract did not commence until July, 1983, TransCanada did not incur any take or pay obligation before that time and Topgas therefore, made no advances in respect of Sellers' Contract under Sellers' Topgas Agreement.

Under Sellers' Topgas Agreement and similar agreements with other producers, TransCanada is obligated to equitably allocate its annual market available for allocation to its allocable gas purchase contracts. TransCanada regards Seller's Contract as an allocable gas purchase contract and is presently taking deliveries of gas thereunder at levels which, TransCanada anticipates, will lead to a ratable allocation of its annual markets to the Contract.

By application dated April 28, 1983, TransCanada requested the Commission to include in Category D (as it then was) of TransCanada's Alberta cost of service a group of gas purchase contracts (designated as Group 6) which was described at p. 13 of the said application as follows:

(f) Group 6

- There was no outstanding take or pay as of October 5, 1982.
- The contracts commenced initial delivery after May 1, 1982, but before May 1, 1983.
- Whether a prepayment obligation would exist cannot be determined until the end of the first contract year.

In making such request, TransCanada was taking the position that, as such contracts were subject to allocation under the Topgas program, did not receive any Topgas payments and had not, prior to the Topgas Program, delivered any gas whatsoever, it was just and equitable that volumes of gas produced thereunder should not attract the financing costs associated with

the payments made by Topgas. In limiting the description of this group of contracts to those which commenced deliveries prior to May 1, 1983, TransCanada intended that its request should not be prospective in effect, but should apply only to contracts which, at the time of the application, were identifiable. TransCanada expected that, if the request was granted, it would subsequently apply for the inclusion of other contracts in Category D as deliveries were commenced thereunder. Sellers' Contract herein would have fallen into this subsequent group of contracts. Though, by Determination 83-06 (TCP), the Commission declined to allow the inclusion of the Group 6 contracts in Category D, TransCanada continues to take the position that the reasoning underlying its application was sound and that, provided such contract is subject to equitable allocation, volumes of gas produced thereunder should not attract the interest costs arising in respect of payments made by Topgas.

Dated at the City of Calgary, in the Province of Alberta, this 29th day of February, 1984.

All of which is respectfully submitted

TRANSCANADA PIPELINES LIMITED

Per: ______________________

E.W.H. Mallabone
Manager, Legal

Communications related to this
Submission should be directed
to:

Mr. E.W.H. Mallabone
Manager, Legal
TransCanada PipeLines Limited
TransCanada PipeLines Tower
530 - 8th Avenue S.W.
P.O. Box 500, Station M
Calgary, Alberta
T2P 3V6

DETERMINATION 84-06
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

REVIEW OF STATEMENT OF OBJECTION

On January 30, 1984 Caribou Mineral Resources Ltd. and Universal Explorations (83) Ltd., (herein called the "Applicants") filed a statement of objection to Determination 83-11 (TCP) with respect to interest costs arising from "interim financing" by TransCanada of certain take or pay payments. The statement of objection is attached as Appendix "A". A further letter dated February 29, 1984 was filed by the Applicants and is attached as Appendix "B".

The Commission elected to review the statement of objection and directed the Applicants to place a notice of the objection in two consecutive issues of "The Herald" in Calgary and "The Journal" in Edmonton, on or before February 11, 1984 and to serve a copy on the Canadian Petroleum Association and Independent Petroleum Association of Canada on or before February 8, 1984.

Submissions with respect to the Applicants' statement of objection were received from the following:

Pembina Resources Limited

Western Decalta Petroleum (1977) Limited

Geocrude Energy Inc.

Prodeco Oil & Gas Co. Ltd.

Independent Petroleum Association of Canada

TransCanada PipeLines Ltd.

Decision

1. Determination 83-11 (TCP) is affirmed except as specified below.

2. If the Commission's decision on the application dated February 29, 1984 by TransCanada for debt/equity financing of take or pay payments results in approval of a financing cost less than the Canadian Imperial Bank of Commerce prime rate plus 7/8 of one percent, the lesser cost shall apply for the month of January, 1984.

Reasons

The application dated February 29, 1984 by TransCanada to recover the cost of debt/equity financing for certain take or pay payments is pending decision by the Commission.

The statement of objection relates to the rate of financing approved for the month of January, 1984. In its submission, TransCanada admits that "... it can borrow at prime under its general lines of credit and at below prime under its commercial paper program ...". Nevertheless, the Commission considers that the take or pay payments will remain outstanding for at least five years and for that reason considers these payments to be long term in nature from their commencement. Therefore, the interim rate of bank prime plus 7/8 of one percent is considered to be reasonable unless a decision on the debt/equity financing application results in a lower rate.

DATED THIS 30th day of March, 1984 at Calgary, Albérta.

ALBERTA PETROLEUM MARKETING COMMISSION

D. C. Hetland
Secretary and Solicitor

APPENDIX "A"

IN THE MATTER of the Natural Gas Pricing Agreement Act, 1975 SA c38 as amended and the Regulations thereunder,

AND IN THE MATTER of Determination 83-11 (TCP)

STATEMENT OF OBJECTION

1. Caribou Mineral Resources Ltd. ("Caribou") and Universal Explorations (83) Ltd. ("Universal"), successor to Universal Explorations Ltd. and The Petrol Oil & Gas Company, Limited, are both oil and gas producing companies holding gas purchase contracts with TransCanada Pipelines Limited ("TransCanada") and effectively bear a proportionate share of the costs of service of original buyers such as TransCanada. Both companies have not signed the Topgas Two proposal.

2. Pursuant to Section 6 of the Natural Gas Pricing Agreement Regulation (Alberta Regulation 307/80 as amended by Alberta Regulations 118/82 and 344/82), Caribou and Universal hereby object to Determination 83-11 (TCP).

3. Specifically, though not so as to limit the generality of the foregoing section 2, Caribou and Universal object to paragraph 1 of the Decision, granting TransCanada's application (attached as Appendix "A") to include in its Alberta Cost of Service, interest costs arising from interim financing by TransCanada for certain take or pay payments.

4. Caribou and Universal contend that the appropriate rate of interest to be included in the Alberta Cost of Service should be the best available rate of interest. We argue that an interest cost of the Prime rate + 7/8% is excessive, is atypical for a major corporate borrower, and is contrary to the interests of both producers and royalty owners. We contend that giving due consideration

to the interim nature of this determination and the loan size and borrowing capacity of TransCanada, the interest rate to be included in the Alberta Cost of Service be no greater than the Prime Rate of interest charged from time to time by the Canadian Imperial Bank of Commerce. We suggest that the Commission may find that the "just and reasonable" least cost of funds may be less than the prime commercial lending rate, as evidenced by Alberta and Southern's financing of its take or pay.

5. Caribou and Universal request that the Commission reconsider its Determination and find that the rate of interest associated with the financing of these prepaid gas payments is inappropriate on the basis enumerated in the foregoing and redetermine a lower interest cost to be borne via Alberta Cost of Service by those producer's who have not executed the Topgas Two proposal.

DATED at the City of Calgary, in the Province of Alberta, this 30th day of January, 1984, and delivered by

CARIBOU MINERAL RESOURCES LTD.

Paul M. Gagnon
Vice-President

UNIVERSAL EXPLORATIONS (83) LTD.

Joseph A. Mercier
President

APPENDIX "A"

"APPLICATION TO INCLUDE TRANSCANADA TAKE OR PAY INTEREST COSTS IN TRANSCANADA'S ALBERTA COST OF SERVICE

1. <u>Request</u>

TransCanada Pipelines Limited ("TransCanada") requests that the Alberta Petroleum Marketing Commission (the "Commission") determine that, from December 30, 1983 and continuing until TransCanada is able to secure long term financing for TransCanada Prepaid Gas (as defined below) it shall be just and reasonable to include and there shall be included in TransCanada's monthly Alberta cost of service, TransCanada Interest Costs (as defined below) arising as a result of interim financing obtained by TransCanada at the rate of the Canadian Imperial Bank of Commerce prime rate plus 7/8%."

(December 19, 1983)

APPENDIX "B"

Caribou Mineral Resources Ltd.
& Universal Explorations ('83) Ltd.
Suite 340, 717 - 7th Ave. S.W.
Calgary, Alta. T2P 3C4

February 29, 1984

Alberta Petroleum Marketing Commission,
Suite 1900, Bow Valley Square IV,
250 - 6th Avenue S.W.
Calgary, Alta. T2P 3H7

Dear Sirs:

Re: Determination 83 - 11 (TCP);
Statement of Objection
dated January 30, 1984

Further to our original Statement of Objection, we wish to amplify certain points for the Commission's benefit in reviewing the Objection.

As set out in the Determination, TransCanada has arranged a short term financing facility at the rate of prime plus 7/8%. Our Statement of Objection contends that a 'least cost' principle should apply to such financings, and that the maximum cost applicable should be the prime rate, giving consideration to the interim nature of the loan, and the credit worthiness of the borrower, TransCanada, which incurred such liabilities due to its nonperformance under the TOPGAS contractual agreement.

We contend that the burden of proof of 'reasonableness' rests with TransCanada Pipelines, as it is seeking regulatory recovery of interest on funds which contractually are its, not producers', legal obligation. Further, in public utility practice the concept of 'least cost' is well established, as an element of "prudency". We contend that no evidence presented by TransCanada in its application, nor cited by the Commission in its approval, demonstrates that:

(i) the means of financing selected is the only appropriate method;

(ii) the interest cost is the lowest obtainable; and

(iii) that any excess cost should not be borne by the applicant (i.e. TansCanada).

We submit that:

1. Bank financing may be appropriate. However, we have been informed by a major chartered bank that a short term facility such as that initially used by Alberta & Southern on an interim basis could be set up within 2 weeks for a prime utility borrower. The key credit consideration would be the borrower's balance sheet. By signing the original TOPGAS agreement, producers facilitated the removal of $1 billion in take or pay financing from TransCanada's balance sheet, significantly improving its credit-worthiness (this point has been documented by reports of TransCanada's lead underwriters).

Further, it is normal for prime corporate borrowers to have money market financing facilities in place for normal corporate purposes.

2. A number of considerably smaller companies are able to borrow funds from a wide range of chartered banks at rates of prime, to prime & 1/4% TransCanada,as one of Canada's major industrial companies, can certainly borrow funds of the magnitude required (or larger) at rates of prime, <u>or less</u>.

3. Any costs in excess of the lowest competitive financing cost represent imprudent financing, & as such should not be borne by producers and royalty owners through Alberta cost of service.

4. Should TransCanada represent that,by definition,the cost of funds to non-signers of TOPGAS II cannot or should not be less than the TOPGAS II financing cost, we maintain that:

   (i) the representation is irrelevant to the issue at hand,i.e. least cost financing of funds contractually owed by TransCanada;

   (ii) the cost & prudency of the TOPGAS II financing rate, while perhaps questionable, is not the subject of this objection.

5. Should TransCanada assert that the risk of take or pay financing is higher than its normal corporate borrowing, we submit that:

   (i) short term borrowing is not usually differentiated by the specific purpose, unless the funds sought are large;

   (ii) the risk in any event belongs to TransCanada, due to its contractual nonperformance;

   (iii) borrowing of funds at the cited rate should not be allowed unless this is the company's average short term borrowing rate or that normally available to a comporable borrower.

6. Should TransCanada assert that the rate is de facto acceptable due to 'widespread producer acceptance', we argue that:

   (i) if believed, this in no way reduces the responsibility of a regulatory body to rule on 'prudency', especially where common practice indicates a lack of prudency;

   (ii) a number of companies signed due to lack of perceived options, and due to pressure from TransCanada;

   (iii) many producers had little option but to sign due to their financial requirements for survival.

In conclusion, we would be prepared to respond to any further questions which the Commission deems appropriate in its review of this Statement of Objection and this filing.

As verbally requested by Mr. Hetland, we also enclose copies of the legal notice published in the Edmonton Journal.

Very truly yours,

Joe Mercier
President, Universal Explorations (83) Limited.

Paul Gagnon
Vice-President, Caribou Mineral Resources Ltd.

AL.1.523

April 30, 1984

INFORMATION BULLETIN RE ALBERTA COST OF SERVICE

The Alberta Cost of Service Information Bulletin for the month of March, 1984 is attached.

The Information Bulletin consists of:

1. Copies of any special Orders or Determinations issued by the Commission during the month with respect to Alberta Cost of Service, and notice of any Statements of Objection which have been received during the month; and

2. Alberta Cost of Service Determinations for the month.

In the case of gas intended to be removed from Alberta, the cost of service determined under Section 11(1), 15(3)(a) and 15(5)(b)(i) of the Natural Gas Pricing Agreement Act for each month is based on estimated figures for that month, adjusted to allow for differences between the estimated and actual figures for the previous month.

In the case of gas intended for consumption within Alberta, the amount estimated as cost of service under Sections 11(2)(a)(ii) and 15(3)(b)(i) of the Act were made under the Commission's general directive for the Alberta cost of service.

All determinations are on gross or higher heating value on a dry basis at 15°C and an absolute pressure of 101.325 kPa (kilopascal).

Yours very truly,

ALBERTA PETROLEUM MARKETING COMMISSION

D. L. Willis
Vice-Chairman

Attachment

INFORMATION BULLETIN
ALBERTA COST OF SERVICE DETERMINATION
PURSUANT TO THE NATURAL GAS PRICING AGREEMENT ACT
MONTH OF MARCH, 1984

Section 15(3)(a)	Cents Per Gigajoule (GJ)*
Alberta and Southern Gas Co. Ltd.	
- Category A	37.329
- Category B	34.725
- Category E	26.998
Canadian Montana Pipe Line Company	35.094
Canadian Montana Gas Company Limited	35.092
Consolidated Natural Gas Limited	43.965
ICG Resources Ltd.	40.202
Many Islands Pipe Line (Canada) Limited	
- Purchased Gas	27.718
- North Sibbald (Agent)	2.928
- Saddle Lake	24.677
- Esther	10.743
Pan-Alberta Gas Ltd.	
- Basic	35.404
- Delivery Points - Joarcam	48.732
- Heart River	37.773
- Windy	73.730
- Lloydminster "B"	60.811
- Lloydminster "A"	66.125
- Fairydell-Bon Accord	37.211
Progas Limited	27.712
Societe quebecoise d'initiatives petrolieres (SOQUIP)	38.793
Sulpetro Limited	29.690
TransCanada PipeLines Limited	
- Average(1)	49.814
- Category A	53.842
- Category B1B2	50.402
- Category B1B3	48.339
- Category B1D2	48.940
- Category D1B2	27.480
- Category D1B3	26.234
- Category D1D2	23.634
- Category E	29.975
Westcoast Transmission Company	
- Husky Oil Ltd.	27.619
- Petrogas Processing Ltd. et al	27.084
Westcoast Transmission Company (Alberta) Limited	
- North	50.166
- Triassic E	.474

.../2

Section 15(3)(b) 33.000

Notes

* Calculated on a gross and dry heating value basis at 101.325 kpa (kilopascal) and 15°C.

Notice

The price adjustment for gas is $0.35/GJ
The Alberta Border Price is $2.790 01/GJ

(1) For purposes of sales within Alberta

PETROLEUM MARKETING COMMISSION

DETERMINATION 84-07 (TCP)
AMENDING DETERMINATION 83-10 (TCP)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

By Determination 83-10 (TCP) sub-categories D_1 and D_2 were established in the multi-tier Alberta cost of service of TransCanada PipeLines Limited (TransCanada) for gas purchase contracts under which repayment or waiver of take or pay payments occurred. Gas purchase contracts in these sub-categories attract no portion of Topgas or Topgas Two take or pay interest costs.

The Commission has advised TransCanada by letter dated March 7, 1984 to the effect that the Commission proposes to restrict access to sub-categories D_1 and D_2 to those gas purchase contracts included in these sub-categories at October 31, 1984. A submission from TransCanada on this proposal has been requested by April 15, 1984.

AMENDMENT

Determination 83-10 (TCP) is hereby amended to provide that for the period April 5, 1984 to October 31, 1984 inclusive no gas purchase contracts shall be added to sub-categories D_1 or D_2 without prior approval of the Commission.

DATED THIS 5th day of April, 1984 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

DETERMINATION 84-08 (A&S)
AMENDING DETERMINATION 83-07 (A&S)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

By Determination 83-07 (A&S) Category E was established in the multi-tier Alberta cost of service of Alberta and Southern Gas Co. Ltd. (Alberta and Southern) for gas purchase contracts under which repayment or waiver of take or pay payments occurred. Gas purchase contracts in this category attract no take or pay interest cost.

The Commission has advised Alberta and Southern by letter dated March 8, 1984 to the effect that the Commission proposes to restrict access to Category E to those gas purchase contracts included in this category at June 30, 1984. A submission from Alberta and Southern on this proposal has been requested by April 15, 1984.

AMENDMENT

Determination 83-07 (A&S) is hereby amended to provide that for the period April 5, 1984 to June 30, 1984 inclusive no gas purchase contracts shall be included in Category E without prior approval of the Commission.

DATE THIS 5th day of April, 1984 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

DETERMINATION 84-09
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

REVIEW OF STATEMENT OF OBJECTION

On February 8, 1984, Western Decalta Petroleum (1977) Limited (herein called the "Applicant") filed a statement of objection to Determination 84-01 (TCP). The statement of objection is attached as Appendix "A". Determination 84-01 (TCP) is attached as Appendix "B".

The Commission elected to review the statement of objection and directed the Applicant to place a notice of the objection in two consecutive issues of "the Herald" in Calgary and "The Journal" in Edmonton, on or before February 19, 1984 and to serve a copy on the Canadian Petroleum Association and Independent Petroleum Association of Canada on or before February 16, 1984.

Pembina Resources Limited and TransCanada PipeLines Limited filed submissions with respect to the statement of objection.

DECISION

Determination 84-01 (TCP) is affirmed.

REASON

The issue in the statement of objection is whether the gas to be produced under the Applicant's gas purchase contract should be free of take or pay financing costs if the Applicant refunds take or pay payments received.

In Determination 83-10 (TCP) the Commission established sub-category D_2 for gas purchase contracts amended by the Topgas Two Agreement under which producers entitled to take or pay payments waived the payments or repaid the payments in full after December 30, 1983. The Applicant's gas purchase contract is not amended by the Topgas Two Agreement and take or pay payments have been received.

A request to extend the limits of eligibility for Category D was dealt with in Determination 84-05. The issue posed by the Applicant parallels the issue that gave rise to Determination 84-05 in that it is suggested that gas to be produced under a gas purchase contract should not bear take or pay financing costs if no take or pay payments are outstanding. The Commission rejects that argument for the reasons given in that determination and does not propose to extend the limits of eligibility for sub-categories free of take or pay financing costs even though repayment by the Applicant would reduce the total take or pay financing costs.

Determination 84-05 is forwarded herewith to the Applicant and is attached to the Alberta cost of service Information Bulletin for the month of February, 1984.

DATED THIS 13th day of April, 1984 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

WESTERN DECALTA

Western Decalta Petroleum (1977) Limited
P.O. Box 2404, 734 - 7th Avenue S.W.
Calgary, Alberta Canada T2P 2M7
Telephone (403) 294-5566

1984 02 08

Alberta Petroleum Marketing Commission
1900 - 250 - 6th Avenue, S.W.
Calgary, Alberta T2P 3H7

Attention: Mr. D.C. Hetland
Secretary and Solicitor

Dear Sir:

RE: DETERMINATION 84-01 (TCP)
ALBERTA COST OF SERVICE
DATED 20 JANUARY 1984
NATURAL GAS PRICING AGREEMENT ACT

Pursuant to The Natural Gas Pricing Agreement Act and Section 6.(1) of The Natural Gas Pricing Agreement Regulations, Alberta Regulation 127/77, please accept this letter as our Statement of Objection to the subject Determination.

Background

In determination 83-10 (TCP) dated 9 December 1983 the Alberta Petroleum Marketing Commission (Commission) granted TransCanada PipeLine Limited's (TransCanada) application dated November 17, 1983 for a revised multi-tiered Alberta Cost of Service to accommodate a program for financing TransCanada's

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1982/83 take-or-pay payment obligations referred to as "Topgas Two". In this application TransCanada requested that additional sub-categories be allowed in its Alberta cost of service so that volumes of gas produced under any contract amended by a Topgas Two Agreement will attract:

(i) Topgas Interest Costs according to whether or not a producer has repaid, after October 5, 1982, all payments made by Topgas Holdings Limited ("Topgas") which are outstanding under such contract; and

(ii) Topgas Two Interest Costs according to whether or not a producer has waived its right under the Topgas Two Agreement to receive payments from Topgas Two or whether or not a producer has repaid, after December 31, 1983, all payments made by Topgas Two which are outstanding under such contract.

In order to implement this scheme, several sub-categories attributable to Topgas Interest Costs and Topgas Two Interest Costs were approved by the Commission as follows:

1. Sub-Category B_1: Contracts in this sub-category consist of those contracts amended by the Topgas Agreement which are not in sub-category D_1 and in respect of which there remains Topgas Prepaid Gas outstanding. The volumes of gas produced under contracts in sub-category B_1 attract, in the applicable Alberta cost of service, those Topgas Interest Costs remaining after deduction for Category A.

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2. <u>Sub-Category D_1</u>: Contracts in this sub-category consist of those contracts amended by the Topgas Agreement in respect of which the producer has, after October 5, 1982, repaid all Topgas payments to Topgas. The volumes of gas produced under contracts in sub-category D_1 attract no portion of the Topgas Interest Costs in the applicable Alberta cost of service.

3. <u>Sub-Category B_2</u>: Contracts in this sub-category consist of those contracts amended by the Topgas Two Agreement which are not in sub-category D_2 and in respect of which after December 30, 1983, there is Topgas Two Prepaid Gas outstanding. The volumes of gas produced under contracts in sub-category B_2 attract, in the applicable Alberta cost of service, those Topgas Two Interest Costs remaining after deduction for Category A.

4. <u>Sub-Category D_2</u>: Contracts in this sub-category consist of those contracts amended by the Topgas Two Agreement in respect of which a producer has waived its right to receive the payment which Topgas Two is obligated to make under such Agreement or under which a producer after December 30, 1983 has repaid all Topgas Two payments. The volumes of gas produced under contracts in sub-category D_2 attract no portion of the Topgas Two Interest Costs in the applicable Alberta cost of service.

....4

For producers that have executed both the Topgas Agreement and the Topgas Two Agreement, the Alberta Cost of Service applicable to their contracts may be B_1 B_2, B_1 D_2, D_1 B_2 or D_1 D_2, depending on the Topgas and Topgas Two repayment status of the particular contract.

In the subject Determination dated 20 January 1984, the Commission granted TransCanada's application dated January 10, 1984 as amended by a letter dated January 19, 1984 for a further revision to TransCanada's multi-tiered Alberta cóst of service to accommodate a program for financing TransCanada's 1982/83 take-or-pay payment obligations to those producers who execute the Topgas Agreement but did not execute the Topgas Two Agreement. This take-or-pay payment obligation (TransCanada Prepaid Gas) arises from a provision in the Topgas Agreement whereby TransCanada must make these payments if it does not fulfill its minimum annual volume obligation. Since TransCanada was unable to fulfill this obligation for the 1982/83 contract year, it made the required TransCanada Prepaid Gas Payments.

In the Jnuary 10, 1984 application, as amended, TransCanada requested that an additional sub-category be allowed in its Alberta Cost of Service so that volumes of gas produced under any contract which is amended by a Topgas Agreement but not a Topgas Two Agreement, will attract interest costs associated with the financing of TransCanada Prepaid Gas. In order to implement this scheme the following sub-category in respect of TransCanada Prepaid Gas Interest Costs was approved by the Commission:

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5. Sub-Category B_3: Contracts in this sub-category consist of those contracts amended by a Topgas Agreement, but not amended by a Topgas Two Agreement. The volumes of gas produced under contracts in sub-category B_3 attract, in the applicable Alberta cost of service, those TransCanada Prepaid Gas Interest Costs remaining after deduction for Category A.

Similar to sub-categories B_2 and D_2, sub-category B_3 is combined with either sub-category B_1 or sub-category D_1 to arrive at category B_1 B_3 or D_1 B_3 depending on whether or not there remains Topgas Prepaid Gas outstanding. TransCanada did not apply for a sub-category D_3 which would be comparable to sub-categories D_1 and D_2 and would provide for the possibility that a producer might wish to waive or return to TransCanada all TransCanada Prepaid Gas outstanding and thereby obtain a reduced Alberta cost of service.

Statement of Objection

Our company has executed the Topgas Agreement but has not executed the Topgas Two Agreement. We have received the appropriate TransCanada Prepaid Gas payments as specified in the Topgas Agreement. We wish to return these TransCanada Prepaid Gas payments to TransCanada for the following reasons:

1. The length of time before TransCanada begins to recover the gas associated with these payments is excessive.

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2. There is some risk that the gas reserves associated with these payments will be depleted before recovery of the payments can be completed.

3. We do not wish to have the payments on our "books" as a future or contingent liability for at least the next ten years.

4. We feel that the effective rate of interest that TransCandaa say they will have to charge in their Alberta cost of service to finance these payments is too high.

Our return of the TransCanada Prepaid Gas payments to TransCanada is, however, contingent upon an appropriate reduction in the applicable Alberta cost of service. At the present time there is no sub-category which provides for the return of TransCanada Prepaid Gas payments as discussed above. We therefore request that the Commission revise and amend Determination 84-01 (TCP) such that commencing as soon as practically possible and continuing until all Prepaid Gas is recovered, volumes of gas produced under any contract which is amended by a Topgas Agreement but not amended by a Topgas Two Agreement will attract TransCanada Prepaid Gas Interest Costs as a component of the Alberta cost of service for such volumes, according to whether or not a producer has repaid after December 31, 1983 all payments made by TransCanada which are outstanding under such contract.

We suggest that an additional alternative sub-category in respect to TransCanada Prepaid Gas Interest Cost will be required as follows:

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6. Sub-Category D_3: Contracts in this sub-category consist of those contracts amended by the Topgas Agreement but not amended by the Topgas Two Agreement in respect of which the producer has, after December 30, 1983, repaid all TransCanada Prepaid Gas payments. The volumes of gas produced under contracts in sub-category D_3 would attract no portion of the TransCanada Prepaid Gas Interest Cost in the applicable Alberta cost of service.

In determining the Alberta cost of service for volumes of gas under any gas purchase contract amended by a Topgas Agreement but not a Topgas Two Agreement, there will be identified one of the alternative sub-categories B_1 and D_1 (as described above) in respect of the applicable Topgas Interest Costs and there will be one of the alternative sub-categories B_3 and D_3 (as described above) in respect of the applicable TransCanada Prepaid Gas Interest Costs. The result of such a procedure is that any contract which has been amended by a Topgas Agreement but not by a Topgas Two Agreement will fall into one of the four categories as follows: B_1 B_3, B_1 D_3, D_1 B_3, D_1 D_3.

TransCanada presently has three distinct and separate sources of financing for its take-or-pay obligations, as follows:

1. Topgas financing.
2. Topgas Two financing.
3. TransCanada Prepaid Gas financing.

The Commission has determined that the interest costs associated with these

....8

separate financings shall be treated separately within the Alberta cost of service. There are presently sub-categories within TransCanada's multi-tiered Alberta Cost of Service which allow a producer to repay all its Topgas payments and/or Topgas Two payments with respect to a specific contract and thereby reduce its Alberta cost of service for gas sold under that contract. It is our view that producers who are paying the interest costs associated with the TransCanada Prepaid Gas financing in the Alberta cost of service should be treated equitable with those who are paying the interest costs associated with the Topgas and Topgas Two financings in the Alberta cost of service. This can be accomplished by allowing such producer the option to return TransCanada Prepaid Gas payments to TransCanada and thereby qualify for sub-category D_3 (described above) in the Alberta cost of service.

Conclusion

We respectfully request that the Commission amend Determination 84-01 (TCP) such that:

(i) there be created a new sub-category D_3 to include those contracts which are amended by the Topgas Agreement but not amended by the Topgas Two Agreement and under which the producer after December 30, 1983 repays all TransCanada Prepaid Gas payments so that volumes of gas produced under such contracts do not attract, as a component of

the associated Alberta cost of service the monthly TransCanada Interest Costs.

If you have any questions regarding this submission or wish to discuss it further, please call me at 294-5373.

Yours truly,
WESTERN DECALTA PETROLEUM (1977) LIMITED

G. Dann, P.Eng.
Manager, Business Affairs

GWD:mr

DETERMINATION 84-01 (TCP)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

APPLICATION

By application dated January 10, 1984, and amended by the letter of January 19, 1984, TransCanada PipeLines Limited ("TransCanada") requests that the Commission revise and amend its Determination 83-10 (TCP) ("Determination 83-10") such that, commencing on December 30, 1983 and continuing until all TransCanada Prepaid Gas is recovered, volumes of gas produced under contracts in Category A of TransCanada's Alberta cost of service attract, as a component of the Alberta cost of service for such volumes, a portion of the TransCanada Interest Costs.

TransCanada further requests that the Commission revise and amend Determination 83-10 such that, commencing on December 30, 1983 and continuing until all TransCanada Prepaid Gas is recovered, volumes of gas produced under any contract which is amended by a Topgas Agreement but not amended by a Topgas Two Agreement attract, as a component of the Alberta cost of service for such volumes TransCanada Interest Costs remaining, after deduction for Category A contracts.

The application as amended is attached as "Appendix A" and Determination 83-10 (TCP) is attached as "Appendix B" without appendices.

DECISION

The application is granted.

REASONS

The new categories to be implemented are created upon the same principles as followed in Determination 83-10 (TCP).

DATED THIS 20th day of January, 1984 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

PROVINCE OF ALBERTA

ALBERTA PETROLEUM MARKETING COMMISSION

APPLICATION TO AMEND TRANSCANADA'S

MULTI-TIERED ALBERTA COST OF SERVICE

I. Request

TransCanada PipeLines Limited ("TransCanada") requests that the Alberta Petroleum Marketing Commission (the "Commission") revise and amend its Determination 83-10 (TCP) ("Determination 83-10") such that, commencing on December 30, 1983 and continuing until all TransCanada Prepaid Gas (as defined below) is recovered, volumes of gas produced under contracts in Category A of TransCanada's Alberta cost of service attract, as a component of the Alberta cost of service for such volumes, a portion of the TransCanada Interest Costs (as defined below).

TransCanada further requests that the Commission revise and amend Determination 83-10 such that, commencing on December 30, 1983 and continuing until all TransCanada Prepaid Gas is recovered, volumes of gas produced under any contract which is amended by a Topgas Agreement (as defined below) but not amended by a Topgas Two Agreement (as defined below) attract, as a component of the Alberta cost of service for such volumes TransCanada Interest Costs remaining, after deduction for Category A contracts.

II. The Topgas Two Program

By an agreement dated May 20, 1982 (the "Topgas Agreement"), TransCanada, Topgas Holdings Ltd. ("Topgas"), and TransCanada's participating producers agreed, inter alia, that Topgas would make certain advances to the pro-

ducers in respect of take or pay gas and that TransCanada would equitably allocate its available gas market to its gas supply available for allocation. Additionally, it was agreed that TransCanada would not be required to pay for gas not taken above a level which is 60% of the 1981/82 minimum annual obligation under each particular contract.

In November of 1983, TransCanada proposed certain amendments to the Topgas Agreement by a form of agreement (the "Topgas Two Agreement") a copy of which was supplied to the Commission in TransCanada's Alberta cost of service application of November 16, 1983. The Topgas Two Agreement set forth a program (the "Topgas Two Program") whereby TransCanada's 1982/83 take or pay obligation would be discharged by Topgas Two Inc. ("Topgas Two") and whereby, among other things, each participating producer agreed to a further reduction of TransCanada's take or pay obligation level.

In its application dated November 17, 1983 (the "November 17 application"), TransCanada requested that the Commission amend and revise TransCanada's multi-tiered Alberta cost of service (as originally established by Determination 82-14 (TCP)) according to the terms set out therein. TransCanada's application was granted by the Commission in Determination 83-10 (TCP). On December 19, 1983, TransCanada applied to the Commission to include the interest costs of financing take or pay payments to be made in respect of gas produced under those contracts which were excluded from the Topgas Two Program by reason that one or more of the producers who were a party to such contracts declined to execute the Topgas Two Agreement.

Such contracts, as amended by the Topgas Agreement but unamended by the Topgas Two Agreement, require that TransCanada itself make take or pay payments for gas not taken during the 1982/83 contract year (such gas being referred to as "TransCanada Prepaid Gas"). On December 21, 1983, the Commission granted this application in Determination 83-11 (TCP). On December 30, 1983, TransCanada paid $78,944,417.78 to producers in respect of 38,372,407 GJ of TransCanada Prepaid Gas. TransCanada, Topgas and Topgas Two have agreed to a Second Closing under the Topgas Two Program, to occur on March 1, 1984. Monies now outstanding in respect of TransCanada Prepaid Gas under those contracts which are included in the Second Closing will be returned to TransCanada and will be replaced by monies paid by Topgas Two in respect of Topgas Two Prepaid Gas (as defined in the Topgas Two Agreement). Thus, TransCanada anticipates that the quantum of monies presently outstanding for TransCanada Prepaid Gas will be reduced in the Second Closing of the Topgas Two program.

III. Modification of TransCanada's multi-tiered Alberta cost of service

With the implemention of the Topgas Two Program, there will be two distinct third party sources of financing for TransCanada's take or pay obligations. In Determination 83-10, the Commission has determined that the interest costs associated with these separate financings shall be treated separately within the Alberta cost of service. TransCanada submits that it is appropriate that the interest costs associated with the financing of TransCanada Prepaid Gas also be treated separately within the Alberta cost of service.

Sub-Category B_3

TransCanada proposes that the Commission amend Determination 83-10 by adding a further sub-category, to be designated sub-category B_3, which would be comprised of those gas purchase contracts amended by a Topgas Agreement but not amended by a Topgas Two Agreement. TransCanada proposes that volumes of gas produced under contracts in sub-category B_3 attract, as a component of the Alberta cost of service for such volumes, the TransCanada Interest Costs remaining after deduction for Category A (as proposed below). Such contracts would include, in particular, those contracts under which, after December 30, 1983, there is TransCanada Prepaid Gas outstanding.

TransCanada, therefore, proposes that in determining the Alberta cost of service for volumes of gas under any gas purchase contract amended by a Topgas Agreement but not a Topgas Two Agreement, there be identified one of the alternative sub-categories B_1 and D_1 (as described in Determination 83-10) in respect of the application of Topgas Interest Costs and that such volumes of gas be assessed TransCanada Interest Costs under the proposed sub-category B_3 of the Alberta cost of service. The result of such a procedure is that any contract which has been amended by the Topgas Agreement but not by a Topgas Two Agreement will fall into one of two categories which are as follows:

TOPGAS INTEREST COST SUB-CATEGORY		TRANSCANADA INTEREST COST SUB-CATEGORY	NEW CATEGORY
B_1	plus	B_3	Category B_1B_3
D_1	plus	B_3	Category D_1B_3

Category A

Determination 83-10 amended Category A as originally set out in Determination 82-14 by requiring that volumes of gas produced under Category A contracts attract a portion of the interest costs of Topgas Two in addition to the Topgas Interest Costs (as defined in the Topgas Agreement) and a portion of the interest costs arising in respect of the take or pay financing under contracts in Category E of TransCanada's Alberta cost of service ("Category E interest costs"). Category A contracts are non-allocable and represent a disproportionately large portion of the gas deliveries to TransCanada's markets. TransCanada submits that it is equitable that volumes of gas produced under contracts in Category A attract, as a component of the associated Alberta cost of service, a portion of the TransCanada Interest Costs.

Accordingly, TransCanada requests that the Commission amend Determination 83-10 such that from December 30, 1983, volumes of gas produced under contracts in Category A of TransCanada's Alberta cost of service attract

take or pay interest costs in a particular month to be calculated as the sum of:

(a) the Topgas Interest Costs and Category E interest costs for the particular month, multiplied by a fraction, the numerator of which shall be the total volumes of gas, expressed in GJs, delivered during the particular month under Category A contracts, and the denominator of which shall be the total volumes of gas, expressed in GJs, delivered during the particular month under Category A, sub-category B_1 and Category E contracts, plus

(b) The Topgas Two Interest Costs and the TransCanada Interest Costs for the particular month, multiplied by a fraction, the numerator of which shall be the total volumes of gas, expressed in GJs, delivered during the particular month under Category A contracts, and the denominator of which shall be the total volumes of gas, expressed in GJs, delivered during the particular month under Category A, sub-category B_2 and sub-category B_3 contracts.

IV. Conclusion

TransCanada respectfully requests that the Commission amend Determination 83-10 (TCP) such that:

(i) Category A be revised in the manner described above in order that vol-

umes of gas produced under Category A contracts attract a portion of the monthly TransCanada Interest Costs; and

(ii) there be created a new sub-category B_3 to include those contracts which are amended by the Topgas Agreement but not amended by the Topgas Two Agreement and under which volumes of gas produced under such contracts attract, as a component of the associated Alberta cost of service, the monthly TransCanada Interest Costs, after deduction for Category A.

Dated at the City of Calgary, in the Province of Alberta this 10th day of January, A.D. 1984.

All of which is respectfully submitted,

TRANSCANADA PIPELINES LIMITED

Per: ______________________

E.W.H. Mallabone
Manager, Legal

Communications related
to this Application
should be directed to:

Mr. E.W.H. Mallabone
Manager, Legal
TransCanada PipeLines Limited
TransCanada PipeLines Tower
530 8th Avenue S.W.
P.O. Box 500
Calgary, Alberta
T2P 3V6

TransCanada PipeLines
TRANSCANADA PIPELINES TOWER 530 EIGHTH AVENUE S W
P O BOX 500 STATION M CALGARY, CANADA T2P 3V6
(403) 269-5611

January 19, 1984

Alberta Petroleum Marketing
Commission
1900 Bow Valley Square IV
250 - 6th Avenue S. W.
Calgary, Alberta
T2P 3H7

Attention: Mr. Don Hetland

Dear Sir:

Re: Application to amend TransCanada's Multi-tiered Alberta Cost of Service.

This will refer to the application to the Alberta Petroleum Marketing Commission (the "Commission") by TransCanada PipeLines Limited ("TransCanada") dated January 10, 1984, wherein TransCanada requested that the Commission amend TransCanada's multi-tiered Alberta cost of service in order to accommodate the interest costs associated with payments made to producers on December 30, 1983 by TransCanada in respect of gas not taken by TransCanada during the 1982/83 contract year ("TransCanada Prepaid Gas").

TransCanada has reviewed the structure of Category A which it proposed in the said application and has concluded that it is equitable that volumes of gas produced under Category A contracts should attract interest costs associated with the financing of the take or pay gas firstly, with respect to take or pay payments made before the end of the 1982/83 contract year and, secondly with respect of the 1982/83 contract year. Accordingly, TransCanada proposes that the formula for the calculation of interest costs under Category A contracts, which appears on p. 6 of the said application, be amended such that Category E interest costs associated with 1982/83 Category E prepayments be calculated together with all other interest costs accruing in respect of 1982/83 prepayments. Accordingly, TransCanada deletes sub-paragraph (a) and (b) which appears on p. 6 of the said application and substitutes the following therefor:

..../2

(a) The Topgas Interest Costs and Category E interest costs for the payments made up to the end of the 1981/82 contract year for the particular month, multiplied by a fraction, the numerator of which shall be the total volumes of gas, expressed in GJs, delivered during the particular month under Category A contracts, and the denominator of which shall be the total volumes of gas, expressed in GJs, delivered during the particular month under Category A, sub-category B_1 and Category E contracts, plus

(b) The Topgas Two Interest Costs and the TransCanada Interest Costs and the Category E interest costs made for the 1982/83 contract year for the particular month, multiplied by a fraction, the numerator of which shall be the total volumes of gas, expressed in GJs, delivered during the particular month under Category A contracts, and the denominator of which shall be the total volumes of gas, expressed in GJs, delivered during the particular month under Category A, sub-category B_2, sub-category B_3 and Category E contracts.

Yours very truly

E.W.H. Mallabone
Manager, Legal
EWHM:ed

Alberta PETROLEUM MARKETING COMMISSION

DETERMINATION 83-10 (TCP)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

APPLICATION

By application dated November 17, 1983 TransCanada PipeLines Limited (TransCanada) applies for a revised multi-tiered Alberta cost of service to accommodate a program referred to as "Topgas Two".

The application is attached as "Appendix A" and Determination 82-14 (TCP) is attached as "Appendix B".

DECISION

1. The application is granted.

2. Sub-category D_2 shall consist of gas purchase contracts amended by the Topgas Two Agreement under which producers actually entitled to take or pay payments have waived the payments or repaid the payments in full after December 30, 1983.

3. Costs of the Topgas Two program apart from interest costs shall be apportioned equally against all purchased gas quantities.

4. This determination shall have no force or effect until implementation of the "Topgas Two" program.

REASONS

The new categories to be implemented are created upon the same principles as followed in Determination 82-14 (TCP).

Sub-categories D_1 and D_2 are established for the limited purpose of inducing a further voluntary reduction in the amount of take or pay payments outstanding.

DATED THIS 9th day of December, 1983 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

DETERMINATION 84-10
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

REVIEW OF STATEMENT OF OBJECTION

On February 7, 1984, Caribou Mineral Resources Ltd. (herein called the "Applicant") filed a statement of objection to Determination 83-09 (TCP) with respect to the financing and administration costs associated with the development, organization and administration of the Topgas Two program for which TransCanada PipeLines Limited (herein called "TransCanada") is required to pay TopGas Two Inc. The statement of objection is attached as Appendix "A".

The Commission elected to review the statement of objection and directed the Applicant to place a notice of the objection in two consecutive issues of "The Herald" in Calgary and "The Journal" in Edmonton, on or before February 17, 1984 and to serve a copy on the Canadian Petroleum Association and Independent Petroleum Association of Canada on or before February 14, 1984.

Submissions were received with respect to the statement of objection from the following:

Universal Exploration (83) Ltd.

Prodeco Oil & Gas Co. Ltd.

Independent Petroleum Association of Canada

TransCanada PipeLines Limited

DECISION

Determination 83-09 (TCP) is affirmed.

REASONS

The statement of objection addresses issues with respect to the financing and administration costs (the "other costs") associated with the development, organization and administration of the Topgas Two program. The issues are set out below together with the Commission's answers to the issues.

Are the "other costs" eligible for inclusion in Albert cost of service?

Determination 77-15 dated September 29, 1977, ruled that take or pay financing costs were costs referred to in section 2(1)(a) of the Natural Gas Pricing Agreement Act as "attributable to the acquisition of the gas by the original buyer." and therefore eligible for recovery through Alberta cost of service. This ruling was upheld by the Public Utilities Board on appeal. The Commission considers the "other costs" to be take or pay financing costs albeit in the nature of administration costs.

Should "other costs" be excluded from recovery in Alberta cost of service because TransCanada had not informed the sellers of such costs or sought their concurrence for the inclusion of such costs in Alberta cost of service?

The eligibility of costs is not dependent upon agreement between the producer and original buyer nor upon the information passing between them.

Should "other costs" be excluded from recovery in Alberta cost of service because the inclusion of such costs in addition to interest costs result in excessive carrying costs in relation to other methods of financing?

The Commission has no reason to believe that the carrying costs are excessive or that the method of financing is not appropriate.

Should "other costs" be excluded from recovery in Alberta cost of service on the basis they were not prudently incurred because the bank fees are inappropriate for the size of the Topgas Two loan facility, and because TransCanada has the borrowing capability for direct financing and that if TransCanada chooses to off-balance sheet finance the associated costs should be borne by TransCanada's shareholders?

The Topgas Two program was accepted by the vast majority of TransCanada's producers and the Commission will not question its prudency. "Other costs" represent actual costs incurred by TransCanada in arm's length dealings with the banking consortium and the Commission has no reason to believe the costs are not just and reasonable for this type of financing.

Should "other costs" be excluded from recovery in Alberta cost of service on the basis they were not prudently incurred because engineering and legal costs are nearly equal to those of Topgas, even though little new documentation was prepared and presented to sellers and that presumably equivalent engineering studies were not required?

Here again, the Commission considers that "other costs" represent actual costs incurred by TransCanada and the Commission has no reason to believe that such costs are not just and reasonable for this type of financing.

Should "other costs" be chargeable only to those contracts falling within categories and sub-categories which have actually received take or pay payments pursuant to the Topgas Two Agreements?

The Commission considers take or pay financing costs to be current costs for purposes of Alberta cost of service without regard as to when the take or pay payments were made or to whom they were made. As current costs, they are recoverable through Alberta cost of service for all gas taken by a buyer monthly. Until 1982 when Determination 82-10 (TCP) was issued prescribing a multi-tiered Alberta cost of service for TransCanada a single cost of service for TransCanada's purchases was in place and all gas purchased in a month bore the costs of financing take or pay payments. This was in accordance with Section 2(2) of the Act which provides as follows:

> "(2) Subject to section 8, the Commission shall determine the Alberta cost of service for an original buyer or (sic) gas intended to be removed from Alberta that shall, unless otherwise ordered by the Commission, apply to all gas purchased in the month by that person as an original buyer."

(Section 8 refers to appeals to the Public Utilities Board).

The multi-tiered Alberta cost of service instituted by Determination 82-10 (TCP) and later replaced by Determination 82-14 (TCP) was considered by the Commission to be justified by the Topgas program which resulted in different financing arrangements with respect to take or pay payments made to participants and non-participants of the program. Topgas also resulted in assured recovery of take or pay payments made to the participants without increasing their share of market during the period of recovery. However, with the exception of Category D, the implementation of multi-tiers did not cause the Commission to deviate from the view that all gas being taken should bear the financing costs of payments made for gas not taken. This view was maintained in Determination 83-10 (TCP) as amended by Determination 84-01 (TCP) under which a revised multi-tiered Alberta cost of service was authorized to accommodate the Topgas Two program.

The Commission considers "other costs" to be in the nature of administration costs to be applied to all flowing gas. The Topgas and Topgas Two programs extend over a number of years and the "other costs" are included in rate base and amortized over the term of the programs. The result is that there is minimal cost impact on flowing gas as shown below.

For the month of February, 1984 TransCanada's Alberta cost of service totalled $55 511 178. Of this amount approximately $63 782 relates to "other costs" of the Topgas Two program which were distributed to categories as follows:

Category	"Other Costs"	Purchases (GJ)	Unit Impact ($/GJ)
A	$ 4 647	7 747 793	.0006
B_1B_2	45 566	75 942 866	.0006
B_1B_3	8 909	14 848 604	.0006
B_1D_2	2 853	4 754 600	.0006
D_1D_2	189	314 999	.0006
D_1B_2	969	1 614 313	.0006
D_1B_3	123	205 529	.0006
E	526	877 187	.0006

The costs, which will decrease over the term of the program as costs are amortized, include the after tax return on capitalized development costs as well as the monthly amortization itself.

DATED THIS 19th day of April, 1984 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

IN THE MATTER of the Natural Gas Pricing Agreement Act, 1975 SA c 38 as amended and the Regulations thereunder,

AND IN THE MATTER of Determination 83-09 (TCP)

STATEMENT OF OBJECTION

1. Caribou Mineral Resources Ltd. ("Caribou") is an oil and gas producing company holding gas purchase contracts with TransCanada Pipelines Limited ("TransCanada") and effectively bears a proportionate share of the costs of service of original buyers such as TransCanada. Caribou has not signed the Topgas Two proposal.

2. Pursuant to Section 6 of the Natural Gas Pricing Agreement Regulation (Alberta Regulation 307/80 as amended by Alberta Regulations 118/82 and 344/82), Caribou hereby objects to Determination 83-09 (TCP).

3. Specifically, though not so as to limit the generality of the foregoing section 2, Caribou objects to paragraph 1 of the Decision as it pertains to the inclusion of:

   "...and other costs for which TransCanada is committed to pay Topgas Two Inc."

   these being:

   "Financing and administration costs associated with the development, organization and administration of the Topgas Two program for which TransCanada is required to pay Topgas Two Inc. as shown in Appendix "B"." (to the application of TransCanada dated November 16, 1983.)

   in TransCanada's Alberta Cost of Service commencing in the month of January, 1984 and continuing thereafter until such amounts are fully recovered.

4. Caribou contends firstly that the inclusion of these costs ("other costs") in the Alberta Cost of Service is inappropriate on the basis that:

   (a) these charges should be borne by TransCanada as a cost associated with satisfaction of its corporate contractural responsibility regarding take or pay obligations to Sellers under its Gas Purchase Contracts as amended.

(b) TransCanada, in its contractural arrangements wi has not informed them, nor sought their concurree inclusion of such "other costs" in its Alberta (vice, all as more particularly stated in Clause 14A ois Two Agreements which read as follows:

> "14A. TransCanada, Seller, Topgas and Topgε acknowledge that it shall be appropriate foada to include in an Alberta Cost of Service, it (at a rate per annum equal to Canadian Prinm time to time plus 7/8 of one percentage po ated with the payments made by Topgas Two under 2A and TransCanada is hereby directed to hold equal to the amount of such interest so inan Alberta Cost of Service in trust for Topgat may direct and to transmit such amount to Topgit may direct."

(c) the inclusion of such "other costs" in additionterest costs at the rate of bank prime plus 7/8 percencluded in the Alberta Cost of Service cause the carryif such payments to be excessive in relation to ots of financing that could be available to satisfy thr pay obligations of TransCanada.

5. Caribou contends secondly, that in the event that itined that TransCanada is entitled to include in its Alber Service such "other costs" associated with the finanpgas Two prepaid gas obligations, then only those amounts d to be prudently incurred should be approved for inclusiorta Cost of Service. In this regard we note:

(a) the bank fees charged, while possibly appropriajor financing such as Topgas ($2,300 Million) are iite for the much smaller Topgas Two loan facility (320 Million depending upon the extent of Seller wai) such fees were charged in TransCanada's initialinced, take or pay payments to gas Sellers (i.e. pre The magnitude of the borrowing is well within the c borrowing capacity of TransCanada. Should it c-balance sheet financing for its own corporate purposes, iated costs should be borne by its own Shareholders. e increases in TransCanada's dividends during ther evidence improved corporate flexibility supportrmal balance sheet borrowing. Furthermore, the redual requirements for pipeline expansion also provid flexibility for direct TransCanada loans which e would be available to such a major corporate bo the rate of prime, with no related costs.

(b) the engineering and legal costs of Topgas Two are nearly equal to those of Topgas despite the fact that little new documentation was prepared and presented to Sellers, nor presumably were equivalent engineering studies required in view of the extremely low TransCanada take during the 82/83 contract year.

(c) should any such costs be deemed appropriate for Alberta Cost of Service, TransCanada's Sellers should have been fully informed as to the magnitude and specifics of such payments.

6. Caribou contends thirdly, that in the event that it is determined that TransCanada is entitled to include in its Alberta Cost of Service any portion of such "other costs" associated with the financing of Topgas Two prepaid gas obligations, then such "other costs", on the basis of equity, fairness and the principle of benefit received, are appropriately chargeable only to those contracts falling within categories and subcategories of TransCanada's multi-tiered Alberta Cost of Service which have actually received prepaid gas payments pursuant to the Topgas Two Agreements. All other Sellers who did not and will not receive payment under the Topgas Two Agreements should not bear the cost of these other Topgas Two financing charges.

7. Caribou requests that the Commission reconsider its Determination and find:

(a) that the inclusion of such "other costs" in excess of interest costs calculated at the rate of Bank prime plus 7/8 percent associated with prepaid gas payments made to Sellers pursuant to the Topgas Two Agreements is inappropriate based on the reasons enumerated in the foregoing, and

(b) redetermine a lower financing cost limited to interest costs only, to be borne via Alberta Cost of Service by those Sellers who have executed the Topgas Two Agreement.

In the alternative, and only in the event that such "other costs" are deemed to be appropriate for inclusion in the Alberta Cost of Service, such "other costs" should be limited only to those costs prudently incurred by TransCanada and appropriate for such inclusion in Alberta Cost of Service to be borne by Sellers, and in this event such costs should only be included in those categories and

subcategories of TransCanada's multi-tiered Alberta Cost of Service for contracts under which prepaid gas payments pursuant to Topgas Two Agreements have actually been received and remain outstanding from time to time.

DATED at the City of Calgary, in the Province of Alberta this

7th day of February, 1984, and delivered by

CARIBOU MINERAL RESOURCES LTD.

Paul M. Gagnon

Paul M. Gagnon
Vice-President

Alberta PETROLEUM MARKETING COMMISSION

DETERMINATION 84-11 (TCP)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

APPLICATION

By application dated January 27, 1984 TransCanada PipeLines Limited (TransCanada) requests that the Commission extend, to February 29, 1984, the time within which TransCanada is required, by Determination 83-11 (TCP) and 84-02 (TCP), to apply for long term financing proposed in respect of certain take or pay payments.

TransCanada also requests the Commission to allow the inclusion, in Alberta cost of service, of the interim financing costs of those payments during January through April, 1984 inclusive. The application is attached as "Appendix A".

DECISION

1. The application is granted except as specified below.
2. The rate of financing for the delivery months of January through April 1984 inclusive shall be the Canadian Imperial Bank of Commerce prime rate plus 7/8 of one percent. If the Commission's decision on the application dated February 29, 1984 by TransCanada for debt/equity financing of take or pay payments results in a lower financing cost, the lesser cost shall apply.

REASONS

The application, dated February 29, 1984, for long term financing has been received and is pending decision by the Commission.

DATED THIS 25th day of April, 1984 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

TransCanada PipeLines
TRANSCANADA PIPELINES TOWER 530 EIGHTH AVENUE S W
P O BOX 500 STATION M CALGARY CANADA T2P 3V6
(403) 269 5611

January 27, 1984

Alberta Petroleum Marketing
Commission
1900 Bow Valley Square IV
250 - 6th Avenue S. W.
Calgary, Alberta

Attention: Mr. Don Hetland

Dear Sir:

Alberta Petroleum Marketing Commission
Determination 83-11 (TCP)

By a letter dated January 19, 1984, TransCanada requested that the Commission extend to February 29, 1984 the time within which it was required to make an application respecting the long term debt/equity financing in respect of its take or pay payments and allow TransCanada to include in its Alberta cost of service interim financing costs relating to such payments in respect of gas delivered during January and February, 1984.

Please consider this letter of request as a replacement for our request of January 19, 1984.

On December 30, 1983, TransCanada, Topgas Two Inc. ("Topgas Two"), Topgas Holdings Limited and TransCanada's participating producers implemented the Topgas Two Program (as described to the Commission in TransCanada's application of November 16, 1983) which amended the 1982 Topgas Program (as described to the Commission by application dated June 18, 1982). In respect of those gas purchase contracts ("non-participating contracts") unamended by the Topgas Two Program, and which remain subject to the Topgas Program, TransCanada paid, on December 30, $78,944,417.78 in respect of 38,372,407 GJ of gas not taken by TransCanada during the 1982/83 contract year (termed "TransCanada Prepaid Gas").

Additionally, on December 30, 1983, TransCanada became obligated under those contracts which were not included in the 1982 Topgas Program ("Category E contracts") to pay a total of $4,537,936.67 in respect of gas not taken during the 1982/83 contract year. The cost of financing these payments was the subject of the Commission's Determination 84-02 (TCP).

..../2

TransCanada and Topgas Two have agreed to a second Closing under the Topgas Two Program, to occur on March 1, 1984, whereby producers who were included in the December Closing can nonetheless participate in the Topgas Two Program. Producers who have received monies from TransCanada in respect of TransCanada Prepaid Gas under the Topgas Program and who subsequently elect to participate in the Topgas Two Program will return those monies to TransCanada and will receive a replacement payment from Topgas Two. TransCanada is presently contacting its producers in respect of the second Closing.

Participation in the Topgas Two second Closing by producers who have already received payments in respect of TransCanada Prepaid Gas will reduce the total monies outstanding in respect of TransCanada Prepaid Gas. Until TransCanada is able to assess the extent of producer participation in the Topgas Two second Closing, TransCanada will not be able to finally determine the total payments outstanding for TransCanada Prepaid Gas and will not, therefore, be able to advise the Commission of the long-term financing which it proposes to put in place in order to support the TransCanada Prepaid Gas asset and in respect of the prepayments under Category E contracts. TransCanada anticipates that it will be able to determine the nature of such financing in the latter part of February, 1984, and would make application to the Commission for approval of such financing at that time, with the intention of implementing such financing as of May 1, 1984. This would provide the Commission with the time necessary to examine the application and render a determination.

TransCanada, therefore, requests that the Commission extend to February 29, 1984 the time within which TransCanada is required to make an application in respect of the long term debt/equity financing which it proposes in respect of "TransCanada Prepaid Gas" and prepayments under Category E contracts, and further requests that the Commission allow TransCanada to include the interim financing costs of TransCanada Prepaid Gas and prepayments under Category E contracts in its appropriate Alberta costs of service in respect of gas delivered during the months of January, February, March and April, 1984.

Yours very truly

TRANSCANADA PIPELINES LIMITED

Per: [signature]

E.W.H. Mallabone
Manager, Legal

DETERMINATION 84-12 (CNG)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

APPLICATION

By application dated July 25, 1983 and amended by letter of December 6, 1983, Consolidated Natural Gas Limited (Consolidated) requests approval to establish separate categories of Alberta cost of service in order to apportion take or pay financing costs. The application (without exhibits) is shown in the attached Appendix "A".

DECISION

The application for a multi-tiered Alberta cost of service is denied.

REASONS

The Commission holds the view that gas purchased under all types of contracts with the same original buyer should have a uniform field price as contemplated by Section 2(2) of the Natural Gas Pricing Agreement Act. This is discussed in Determination 84-05.

Where the Commission has deviated from the single cost of service it was to accommodate specific agreements as to financing arrangements for take or pay payments with producers representing a majority of gas supply. The amount of take or pay financing required apart from the Topcon financing is not, at present, of sufficient magnitude to warrant a separate tier of Alberta cost of service for Topcon participants, nor does the program apply to the majority of gas supply.

DATED this 30th day of April, 1984 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

APPENDIX "A"

CONSOLIDATED NATURAL GAS LIMITED

Suite 1600, 333 - 11th Avenue S.W., Calgary, Alberta T2R 1L9

Telephone (403) 263-8040, Telex 038-25524

December 6, 1983
File No: 3607-10

The Alberta Petroleum Marketing Commission
1900, 250 - 6th Avenue S.W.
Calgary, Alberta
T2P 3H7

Attention: Mr. V. Thomas
General Manager, Natural Gas

Dear Mr. Thomas:

Re: Consolidated Natural Gas Limited
Application dated July 25, 1983
For a Multi-Tiered Alberta Cost-Of-Service-Docket Number 83-08

We present the following response to your request for additional information dated August 24, 1983 with respect to the above noted application.

Consolidated Natural Gas Limited (Consolidated), Canterra Energy Ltd. (Canterra) and TransCanada Pipelines Limited (TransCanada) entered into an agreement dated July 13, 1983 (a copy attached hereto as Exhibit I) wherein the parties amended the gas purchase contract dated April 12, 1969 between Consolidated and Canterra, and the gas sales contract dated May 23, 1972 between Consolidated and TransCanada. This agreement does not change the guaranteed daily nomination provisions outlined in our letter of April 11, 1983 with respect to the non-participating producer contracts for a period continuing to October 31, 1984. Thereafter, Consolidated and TransCanada are required to nominate on a daily basis for a volume of gas not less than 70% of the minimum annual obligation. Section 3 of the amendment outlines the nomination procedures and further provides for nomination levels to exceed 70% under certain conditions which are outlined at subsection 3 (b).

RECEIVED

DEC -7 1983

ALBERTA PETROLEUM
MARKETING COMMISSION

Current estimates indicate that the Canterra volumes will constitute the following percentages of Consolidated's annual production other than the Kaybob Producers:

CONTRACT YEAR	% OF PRODUCTION
1982-83	62%
1983-84	58%
1984-85	54%
1985-86	52%

Any inquiries in regard to this matter can be directed to the undersigned.

Yours very truly,

CONSOLIDATED NATURAL GAS LIMITED

C.A. Harvey
Chief Accountant

CAH/ldl
Attachment

In the Matter of an Application By
Consolidated Natural Gas Limited to the
Alberta Petroleum Marketing Commission for
Approval of a Multi-Tiered Alberta Cost of
Service for Consolidated Natural Gas Limited
July 25, 1983

PROVINCE OF ALBERTA
ALBERTA PETROLEUM MARKETING COMMISSION
APPLICATION BY CONSOLIDATED NATURAL GAS LIMITED
FOR APPROVAL OF A MULTI-TIERED
ALBERTA COST OF SERVICE

Request

Consolidated Natural Gas Limited ("Consolidated") requests that the Alberta Petroleum Marketing Commission ("Commission") determine that there shall be established separate and distinct categories of Consolidated's Alberta cost of service in respect of separate and distinct categories of gas purchase contracts, which categories arise by reason of take or pay payments made or to be made by TransCanada PipeLines Limited ("TransCanada") to Consolidated under the 1972 Agreement (as defined below), or by reason of payments to be made by Topcon Holdings Alberta Limited ("Topcon") to or for the benefit of Consolidated's gas producers as a result of the 1983 Consolidated Allocation Program (as hereinafter described).

II INTEREST COSTS

A. TransCanada Interest Costs Under the 1972 Agreement

On May 23, 1972 TransCanada and Consolidated entered into an agreement ("1972 Agreement") whereby TransCanada is obligated to request from Consolidated and pay for, or nevertheless pay for, if available and not requested certain volumes of gas which Consolidated is obligated to take under the gas purchase contracts which Consolidated has entered into with certain Alberta gas producers ("Supply Contracts"). In any contract year during the term of the 1972 Agreement in which TransCanada fails to request at minimum obligation under the 1972 agreement and under each Supply Contract, TransCanada is required to make take or pay payments to Consolidated in respect of gas not requested. Consolidated, pursuant to the Supply Contracts, distributes such take or pay payments to those of its producers who were nominated below minimum obligation during such contract year.

The current status of gas not taken but paid for by Consolidated and TransCanada was reviewed for the Commission by letter from Consolidated to the Commission dated February 16, 1983, a copy of which appears herewith under Tab "1" and was further detailed to the Commission by letter from Consolidated, to the Commission dated April 11, 1983, a copy of which appears

herewith under Tab "2". The take or pay payments received by the producers under the Supply Contracts have been financed by TransCanada at prime rate plus 7/8 of one percent. As of January 11, 1983, Consolidated's producers had received and there remains outstanding the sum of $14,404,686.00 in take or pay payments paid by Consolidated to its producers for gas not taken under the Supply Contracts. As a result of Commission Determination 83-03 (CNG) dated April 5, 1983, TransCanada's cost of financing these take or pay payments ("TransCanada Interest Cost") have been included in Consolidated's Alberta cost of service from December 1982.

B. Topcon Interest Costs under the 1983 Consolidated Allocation Program

By application to the Commission dated June 2, 1983, Consolidated described an allocation program ("1983 Consolidated Allocation Program") which Consolidated, TransCanada and Topcon have offered to Consolidated producers in the form of agreement which appears herewith under Tab "3" hereto ("Producer Agreement"). On Closing, (as defined in the Producer Agreement), Topcon will pay participating producers for the 1980/81 and 1981/82 Additional Volumes, (as defined in the Producer Agreement) together with the Equalization Payment (as defined in the Producer Agreement). Topcon will also pay each participating producer an amount equal to its "Prior Payments", "Prior Payments" is used herein to mean the outstanding take or pay payments presently held by each participating producer under each Supply Contract and received from Consolidated prior to January 11, 1983. The Prior Payments will be returned by each participating producer to Consolidated who will return the Prior Payments to TransCanada. In order to make its various payments, Topcon will borrow funds at the Canadian Prime Rate, (as defined in the Producer Agreement) plus 7/8 of 1% per annum. In its June 2, 1983 application to the Commission, Consolidated has requested that the Commission allow the inclusion of this interest ("Topcon Interest Cost") in Consolidated's Alberta cost of service.

III Multi-Tiered Alberta Cost of Service

In its Determination 82-14 (TCP), dated November 23, 1982, the Commission established a five tiered Alberta cost of service for TransCanada gas purchase contracts in order to "more fairly assess the costs of take or

pay financing against the beneficiaries of take or pay payments".

Consolidated proposes that the Commission establish a six tiered Alberta cost of service for Consolidated in order to apportion among its producers both the continuing TransCanada Interest Cost and the Topcon Interest Cost. The six tiers are as follows:

<u>Category A:</u> Under nine of the Supply Contracts ("Kaybob Supply Contracts") the producers' obligation to deliver and Consolidated's obligation to take gas are defined by order of the Energy Resources Conservation Board ("Board") (Board Approvals #2995 and #2833, dated December 6, 1976 and October 5, 1979 respectively, as amended). Consolidated cannot require deliveries in excess of the levels established by the Board, nor can it take volumes below such levels. The purpose of the Board's order is to maximize recovery of liquids from the subject reserves. The orders require the re-injection of a portion of the processed gas in order to maintain appropriate reservoir pressure. The non-injected portions of the gas produced under the Kaybob Contracts are delivered to Consolidated . Because of the Board orders, the Kaybob Supply Contracts cannot be allocated within the 1983 Consolidated Allocation Program. The Kaybob Supply Contracts thus enjoy the advantage of delivery of all available gas to the detriment of deliveries of gas under the allocable Supply Contracts.

Consolidated proposes that volumes of gas produced under Category "A" Supply Contracts include as a component of the Alberta cost of service for those volumes a portion of the TransCanada Interest Cost, if any, and the Topcon Interest Cost. None of the Supply Contracts are in respect of solution gas, nor could they otherwise be characterized as 100% load factor contracts. Thus, Consolidated proposes that Category "A" include only the Kaybob Supply Contracts.

Consolidated proposes that commencing on Closing the costs to be included under Category A of a Consolidated multi-tiered Alberta cost of service consist of that proportion which the total monthly volume of gas delivered to

Consolidated under the Category A contracts, measured on a heat content basis (GJ), is of the total monthly volume of gas delivered under Categories, A, B, C, and E (as described herein), measured on a heat content basis, and applied to the aggregate of the TransCanada Interest Costs and the Topcon Interest Costs.

Category B: This category consists of the Supply Contracts which are amended by Producer Agreements, and for which a producer will receive payments from Topcon in respect of the 1980/81 and 1981/82 contract years ("Additional Volumes Payment") and the Equalization Payment, but in respect of which no Prior Payments have been made.

Consolidated proposes that, commencing on Closing, volumes of gas produced under Category B Supply Contracts include, as a component of the Alberta cost of service for those volumes a portion of the interest costs associated with the Additional Volumes Payment ("Additional Volumes Cost"), and the Equalization Payment ("Equalization Payment Cost") but should not include any portion of the interest costs associated with payments to be made by Topcon to replace the Prior Payments, nor any portion of the TransCanada Interest Cost.

Consolidated submits that volumes of gas delivered under Category B contracts attract, as a component of the Alberta cost of service for those volumes, a proportionate share of the Additional Volumes Costs, and Equalization Payment Costs, after deduction for Category A contracts, which the Additional Volumes Payments plus the Equalization Payments made by Topcon in respect of Category B contracts, outstanding at the beinning of the month, is of the total Additional Volumes Payments plus the total Equalization Payments made by Topcon on volumes outstanding at the beginning of the month.

Category C: This category consists of those Supply Contracts which are amended by Producer Agreements, and for which a producer will receive payments under each of the categories set out in paragraph 2 of the Producer Agreement including payment in respect of the Prior Payments and the Equalization Payments. Consolidated submits that, commencing on Closing, the volumes of gas produced under Category C contracts attract, as a component of the Alberta

cost of service for those volumes, a proportionate share (calculated as hereinafter described) of the Additional Volumes Costs and the Equalization Payment Costs, together with the interest costs of payments made in respect of the Prior Payments, after deduction for Category A contracts. Consolidated submits that the share of Additional Volumes costs and Equalization Payment Costs should be calculated each month as that proportion of the remainder of the Additional Volumes Costs and Equalization Payment Costs for that month, after deduction of those included in the Alberta cost of service for Category 'A' contracts, which the monies paid to producers by Topcon under this category of contracts as Additional Volumes Payments and Equalization Payments, outstanding at the beginning of the month is of the total Additional Volumes Payments and Equalization Payments outstanding at the beginning of the month.

Consolidated submits that the volumes delivered to Consolidated under Category C should also attract, as a component of the Alberta cost of service for those volumes, the interest costs of the related Prior Payments, after deduction for Category A contracts.

Category D: This category consists of those supply contracts which are amended by Producer Agreements and which are allocated under the 1983 Consolidated Allocation Program, but in respect of which a producer has repaid to Topcon after Closing, all monies advanced by Topcon on account of Prepaid Gas (as defined in the Producer Agreement).

Consolidated submits that the volumes of gas delivered under Category "D" Supply Contracts do not include, as a component of the monthly Alberta cost of service for such volumes, any portion of the Topcon Interest Cost or any portion of the TransCanada Interest Cost accruing after Closing.

Category E: Consolidated proposes that, prior to Closing this Category consist of all Supply Contracts in respect of which Prior Payments were made, and that subsequent to Closing consist of the Supply Contracts in respect of which Prior Payments were made but which are not amended by Producer Agreements.

Consolidated submits that the volumes of
Supply Contracts include, as a component
service for such volumes, the monthly Tra
month subsequent to Closing, after deduct
associated with volumes of gas produced in
that month.

<u>Category F</u>: Consolidated proposes that,
consist of all Supply Contracts in respec
made, and that subsequent to Closing cons
respect of which no Prior Payments were m
Producer Agreement.

Consolidated submits that the volumes of
Supply Contracts do not include, as a com of
service for such volumes, any portion of ost.

<u>General</u>:

In the event that all of Consolidated's phe
1983 Consolidated Allocation Program, the
Payments outstanding after Closing and th
continuance of the proposed Categories E ed
producers decline to participate in the am,
Prior Payments will remain outstanding inf
such producers, and the proposed Categori
Closing in order to recover the continuin

II <u>Financing and Administration Costs</u>

By application dated June 2, 1983 Consolin to
determine that Consolidated may include con
costs in its Alberta cost of service. Co
Financing and Administration Costs (as de
Application) be recovered from all volumeY
Contracts.

III Conclusion:

For the foregoing reasons, Consolidated respectfully requests that:

(1) The Commission determine that there shall be a six-tiered Consolidated Alberta cost of service in respect of the Supply Contracts as follows:

Category A: consisting of the Kaybob Supply Contracts as described herein;

Category B: consisting of those Supply Contracts amended by and allocated under Producer Agreements whereby the participating producer receives from Topcon only

a) the Additional Volumes Payment, and

b) the Equalization Payment

Category C: consisting of those Supply Contracts amended by and allocated under Producer Agreements whereby the participating producer receives from Topcon;

a) the Additional Volumes Payment,

b) the Equalization Payment, and

c) payment in respect of the Prior Payments;

Category D: consisting of those Supply Contracts amended by and allocated under Producer Agreements whereby the participating producer, after Closing, returns all payments made by Consolidated and Topcon in respect of Prepaid Gas;

<u>Category E</u>: consisting of those Supply Contracts, not amended by Producer Agreements, in respect of which Prior Payments have been made;

<u>Category F</u>: consisting of those Supply Contracts, not amended by Producer Agreements, in respect of which no Prior Payments have been made to the producer.

(2) The Commission further determine that:

(a) the monthly TransCanada Interest Cost and the monthly Topcon Interest Cost be allocated among the foregoing categories in the manner described herein; and

(b) the Financing and Administration Costs be recovered in respect of all volumes of gas produced under the Supply Contracts.

DATED at the City of Calgary, in the Province of Alberta, this 25 day of July, 1983.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

W.J. DEMCOE
Vice President, Finance and Secretary

Please be advised that Determination 84-04 (PAG) as attached was issued on March 9, 1984 and was inadvertently omitted in the Alberta cost of service Information Bulletin for the month of February, 1984.

Alberta PETROLEUM MARKETING COMMISSION

DETERMINATION 84-04 (PAG)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

APPLICATION

By application dated December 28, 1983, and amended by letters dated January 13, 1984 and February 20, 1984, Pan-Alberta Gas Ltd. (herein called Pan-Alberta) requests approval to include in its Alberta cost of service (1) carrying costs, being costs incurred in financing take or pay payments, (2) any producer repayments due under Pan-Alberta's take or pay advance payment arrangement and not received. The application is attached as Appendix "A" hereto.

DECISION

The application is granted.

REASONS

The Commission has examined the application and has found it to be consistent in principle with the previous application of Pan-Alberta resulting in Determination 83-01 (PAG).

DATED THIS 9th day of March, 1984 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

PROVINCE OF ALBERTA

ALBERTA PETROLEUM MARKETING COMMISSION

0033B

In The Matter of the Natural Gas Pricing Agreement Act being Chapter N-4 of the Revised Statutes of Alberta 1980, as amended, and the regulations pursuant thereto; and

In The Matter of an Application by Pan-Alberta Gas Ltd. for inclusion in its Alberta Cost of Service carrying costs associated with take or pay payments for the contract year beginning November 1, 1982 and ending October 31, 1983.

A. APPLICATION

Pan-Alberta Gas Ltd. (hereinafter called "Pan-Alberta") hereby applies to the Alberta Petroleum Marketing Commission (hereinafter called "the Commission") for inclusion in its Alberta Cost of Service each month during the term of the take or pay financing:

1. the carrying costs, being costs incurred in financing take or pay payments; and
2. any producer repayments due under Pan-Alberta's take or pay advance payment arrangement and not received

both in respect of the contract year ending October 31, 1983.

B. INTRODUCTION

As Pan-Alberta's market and gas supply has not changed materially since our Applications of 1978 11 28, 1979 11 29, 1980 12 01, 1981 12 16 and 1982 12 22 were made to the Commission, parts of this Application have been taken from the above and included herein for ease of reference. However, we consider these previous Applications as supporting documents to this Application.

C. PREVIOUS YEAR'S STATUS

1. Background

Enactment of the Natural Gas Pricing Agreement Act (hereinafter called "NGPAA") effective November 1, 1975, among other things substantially altered gas purchase contract pricing provisions. Unfortunately, the legislation is not clear with respect to normal contract provisions for take or pay. The NGPAA relates to "the price of gas delivered" in each month under a gas sales contract and nothing is mentioned about gas which is "not delivered", i. e. take or pay gas. As a result, there is no established practice of a permanent nature in place at present concerning take or pay.

Prior to enactment of NGPAA, a buyer was able to enforce take or pay clauses in sales agreements. This mechanism, in effect, had Pan-Alberta's customers financing Pan-Alberta's take or pay commitments in gas purchase contracts provided there was a matching of gas purchase and gas marketing conditions. In addition, buyers of natural gas were able to recover in kind gas paid for but not taken pursuant to contract provisions. The effect of this contractual provision was that buyers would realize any price appreciation from the point in time they paid for a quantity of gas to the time at which they actually took the gas. The potential gain served as one means by which a buyer could offset his costs related to payments for gas not taken.

The effect of current NGPAA pricing legislation confers any price appreciation on gas paid for but not taken upon the producer, for it stipulates the price to be paid to a producer on gas when it is delivered. Due to jurisdictional uncertainties, the NEB has precluded Westcoast Transmission Company Limited from fulfilling take or pay payment obligations under its purchase contracts with Pan-Alberta. Accordingly, the value of these sales contracts as a source of financing producer take or pay payments is questionable at this time.

2. 1975/76 Contract Year

Pan-Alberta experienced take or pay with its producers for the 1975/76 contract year. Pan-Alberta, in an attempt to maintain its financial viability, which was seriously jeopardized through the introduction of NGPAA, entered into negotiations with producers to recover carrying costs. The results of these negotiations was that Pan-Alberta would receive in repayment the principal advanced together with approximately 8% interest which would serve to partially offset Pan-Alberta's borrowing costs. The outcome of these negotiations was a take or pay price of $\$26.62/10^3m^3$ (75¢/Mcf) (in accordance with non-regulated contract price provisions) and a repayment price schedule for recovery of take or pay monies advanced escalating $\$2.13/10^3m^3$ (6¢/Mcf) per contract year calculated on a contract year basis. For recoveries calculated on a monthly basis the prices set forth above were in effect for the respective calendar years. The $\$2.13/10^3m^3$ (6¢/Mcf) escalation represents the allowance afforded to Pan-Alberta to recover part of its carrying costs.

For the 1975/76 contract year, take or pay payments were claimed by producers for a total of 94 918.7 10^3m^3 (3,369,018 Mcf). These deficiency volumes have now been fully recovered as follows:

	1975/76 T/P OBLIGATION	RECOVERED VOLUMES	NET T/P OBLIGATION
Contract Year Basis	25.6	25.6	--
Monthly Basis	69.3	69.3	--
TOTAL (10^6m^3)	94.9	94.9	--
TOTAL (MMcf)	3,369	3,369	--

The net carrying costs on these advances were not included in Pan-Alberta's Alberta Cost of Service.

The above situation occurred, absent precedents, under the NGPAA and was designed as an interim solution anticipating that regulation would provide another mechanism to allow Pan-Alberta to remain whole.

3. 1976/77 Contract Year

Pan-Alberta did not experience any take or pay with its producers for the 1976/77 contract year.

4. 1977/78 Contract Year

During the 1977/78 contract year, Pan-Alberta incurred a take or pay obligation of 192 989.8 10^3m^3 (6,849,928 Mcf). Negotiations with producers took the form of two suggested interim solutions, namely the waiver proposal and the advance payment proposal (sample form letter and Letter Agreements provided in the previous Application dated 1979 11 29).

Pan-Alberta's take or pay negotiations with producers have produced the following results for the 1977/78 contract year:

	1977/78 T/P OBLIGATION		RECOVERED VOLUMES	NET T/P OBLIGATION
Effective Waiver	125.3	(65%)	19.2	106.1
Advance Payment[1]	27.3	(14%)	0.3	--
Regulated Field Price	36.0	(19%)	36.0[2]	--
Undecided	4.4	(2%)	1.3	3.1
TOTAL (10^6m^3)	193.0		56.8	109.2
TOTAL (MMcf)	6,850		2,016	3,878

NOTE: 1 Recovery Not Required
2 Recovered because of Peaking Requirements

Currently only carrying costs associated with the advance payments are included in Cost of Service. During the last four years, we have continued to negotiate with producers who are still undecided or requested that the regulated field price (less price adjustment) in our gas purchase contracts be applied. The above numbers have changed since last

year's application mainly due to some of our producers previously indicating that they would opt for the Advance Payment, now deciding in favour of the Waiver.

5. <u>1978/79 Contract Year</u>

During the 1978/79 contract year, Pan-Alberta incurred a take or pay obligation of 228 544.1 10^3m^3 (8,111,823 Mcf). Negotiations with producers followed the same format as the 1977/78 contract year with the following results:

	1978/79 T/P OBLIGATION		RECOVERED VOLUMES	NET T/P OBLIGATION
Effective Waiver	201.0	(88%)	11.6	189.4
Advance Payment[1]	12.3	(5%)	--	--
Regulated Field Price	0.0	(0%)	--	0.0
Undecided	15.2	(7%)	2.7	12.5
TOTAL (10^6m^3)	228.5		14.3	201.9
TOTAL (MMcf)	8,112		508	7,166

NOTE: [1] Recovery Not Required

Currently carrying costs associated with the advance payments are included in Cost of Service.

Over the past four years, we have negotiated with producers who are still undecided or requested that the regulated field price (less price adjustment) in our gas purchase contracts be applied. Currently, only five percent (5%) of the 1978/79 take or pay obligation remains unresolved.

6. <u>1979/80 Contract Year</u>

During the 1979/80 contract year Pan-Alberta incurred a take or pay obligation of 80 119.5 10^3m^3 (2,843,740 Mcf). Negotiations with producers followed the same format as the previous two years with the following results:

	1979/80 T/P OBLIGATION		RECOVERED VOLUMES	NET T/P OBLIGATION
Effective Waiver	68.4	(85%)	0.3	68.1
Advance Payment[1]	3.8	(5%)	--	--
Regulated Field Price	0.3	(0%)	--	0.3
Undecided	7.6	(10%)	--	7.6
TOTAL ($10^6 m^3$)	80.1		--	76.0
TOTAL (MMcf)	2,844		--	2,698

NOTE: [1] Recovery Not Required

Over the past four years, we have negotiated with producers who are still undecided or requested the regulated field price (less price adjustment) in our gas purchase contracts be applied. Currently only ten percent (10%) of the 1979/80 take or pay obligation remains unresolved.

7. <u>1980/81 Contract Year</u>

During the 1980/81 contract year, Pan-Alberta incurred a take or pay obligation of 656 364.8 $10^3 m^3$ (23,296,835 Mcf). Negotiations with producers followed the same format as the previous three years with the following results:

	1980/81 T/P OBLIGATION		RECOVERED VOLUMES	NET T/P OBLIGATION
Effective Waiver	475.2	(73%)	--	475.2
Advance Payment[1]	112.1	(17%)	--	--
Regulated Field Price	2.7	(0%)	--	2.7
Undecided	66.4	(10%)	--	66.4
TOTAL ($10^6 m^3$)	656.4		--	544.3
TOTAL (MMcf)	23,297		--	19,319

NOTE: [1] Recovery Not Required

We are still negotiating with those producers who are undecided or requesting the regulated field price. Currently only ten percent (10%) of the 1980/81 take or pay obligation remains unresolved.

8. 1981/82 Contract Year

During the 1981/82 contract year, Pan-Alberta incurred a take or pay obligation of 598 629.5 10^3m^3 (21,247,594 Mcf). Negotiations with producers followed the same format as the previous four years with the following results:

	1981/82 T/P OBLIGATION		RECOVERED VOLUMES	NET T/P OBLIGATION
Effective Waiver	308.6	(52%)	--	308.6
Advance Payment[1]	54.8	(9%)	--	--
Regulated Field Price	--	(0%)	--	--
Undecided	235.2	(39%)	--	235.2
TOTAL (10^6m^3)	598.6		--	543.8
TOTAL (MMcf)	21,248		--	19,301

NOTE: [1] Recovery Not Required

We are still negotiating with those producers who are undecided. Currently 39% of the 1981/82 take or pay obligation remains unresolved.

D. CURRENT YEAR'S POSITION

1. Market Impact on Take or Pay

Pan-Alberta purchases and markets natural gas and in the course of its affairs, contracts with producers of natural gas, transmission companies and distribution companies. These related businesses are capital intensive requiring facilities that provide many years of service. The long term nature of these related businesses commands that contracting with these organizations be on a long term basis as well. Therefore, to explain the reasons for take or pay, one has to firstly explain the historical contract obligations incurred which were outlined in Pan-Alberta's previous Application to the Commission dated 1978 11 28 and then relate these circumstances to the current conditions that result in precipitating take or pay obligations.

Pan-Alberta has historically purchased gas from its producers at an 80 percent (80%) load factor. It believes a comparable sales load factor should be 85 percent (85%), leaving a 5 percent (5%) difference between purchasing and selling conditions as an estimated allowance to provide deliverability reliability for sales obligations. Pan-Alberta has two major sales contracts with Westcoast Transmission Company Limited (hereinafter called "Westcoast") which are significantly below an 85% load factor level for the 1982/83 gas contract year. As outlined in detail in previous take or pay applications, Pan-Alberta can gain a perspective on its potential gas purchase take or pay obligations related to these two sales contracts. Pan-Alberta submits that gas purchase take or pay obligations occurring from normal operation of the two Westcoast sales contracts could aggregate 594 $10^6 m^3$ (21.1 Bcf).

Further, we have been advised by Westcoast that as a result of the dramatic cutback of their export markets because of U. S. Border Price increases, Westcoast would experience a take or pay problem with their own producers. Therefore, Pan-Alberta as a supplier to Westcoast will be put into take or pay by a minimum of some fifty-eight percent (58%) for the contract year ending December 31, 1982, which translates to a further reduction in sales by Pan-Alberta of 702 $10^6 m^3$ (24.9 Bcf). Negotiations with Westcoast are currently going on with respect to payments for take or pay.

2. 1981/82 Contract Year Take or Pay

Calculations indicate that the take or pay obligations will be in the order of 821 $10^6 m^3$ (29.2 Bcf). In addition, Pan-Alberta has allocated this take or pay equally amongst all contracts except for those where we have negotiated a reduced minimum annual volume obligation and solution gas contracts.

Under the terms of Pan-Alberta's gas purchase contracts, payments for take or pay gas are due sixty (60) days after the end of the contract year in which the take or pay was incurred. Therefore, gas paid for but not taken during the 1982/83 contract year ending October 31, 1983, will incur carrying costs commencing December 31, 1983.

Since our position has not changed with respect to increased exposure to take or pay as a result of legislative changes that occurred November 1, 1975, and the successful results of producer negotiations pursuant to our proposed two interim solutions, Pan-Alberta expects to continue a similar course this year as that of the last five (5) years.

3. Measures Taken to Reduce Take or Pay Obligation

The following measures have been taken to reduce and minimize the take or pay obligation for the 1982/83 contract year:

a) Cessation of Purchasing

Although Pan-Alberta has never made an official announcement, cessation of gas purchasing effectively closed in mid-1977 for existing markets. Any gas purchase contracts signed since then represent,

(i) a culmination of negotiations begun prior to mid-1977

(ii) commitments to buy small quantities of gas from offsetting acreage to prevent drainage and other conservation schemes; and

(iii) commitments in respect of solution gas

b) Producer Testing

Where a producer fails for any fourteen (14) consecutive days to deliver to Pan-Alberta the maximum day volume requested, Pan-Alberta has reduced the daily contract quantity in accordance with the contract.

c) Force Majeure

In the event of a force majeure occurrence which prevented Pan-Alberta from accepting gas deliveries, Pan-Alberta invoked the force majeure provision in the gas purchase contract which reduced the minimum annual volume obligation.

d) Zero Nominations

As minimum annual volume obligations were satisfied, fields were given zero nominations thereby allowing production from other fields to satisfy market requirements.

e) Computer Monitoring

Computer monitoring of the supply/demand balance and take or pay exposure, on a daily basis, enhances the ability to react to changing circumstances throughout the gas contract year.

f) Producer Negotiations

Negotiations have been made with producers to minimize take or pay obligations and to accommodate maintenance shutdowns and testing programs. Included in this category would be credits carried forward to following contract years as a result of significant over-deliveries by producers.

g) Producer Shortfall

Where producers have failed for whatever reason to deliver the volumes requested, this shortfall has been credited toward our minimum annual volume obligation. Included in this amount would be shortages as a result of failure to meet the quality specifications included in the gas purchase contract, unclaimed producer force majeures, shortfalls resulting from the use of "a daily higher-of calculation" and other supply shortfalls.

h) Gas Exchanges

During periods of extraordinary market demand or temporary failure of our gas supply as a result of producer problems and transmission outages, gas exchanges have been arranged with other buyers to circumvent loss of markets.

i) Additional Sales

Pan-Alberta has obtained additional sales within Alberta to the Alberta Utilities, Petro-Canada, Norcen, Alberta Natural Gas, Gas Alberta and Sulpetro, which reduced our potential take or pay exposure.

E. IMPACT ON PAN-ALBERTA

1. Cost of Service Impact

The monthly carrying costs for Pan-Alberta's payments for gas not taken will be determined by the volume of take or pay gas, the price to be paid for such gas and the financing secured. Although the volume of take or pay gas can be reasonably estimated at this time, the applicable pricing, financing arrangements and the results of producer negotiations have not been resolved.

As a result of current pricing legislation, there exists uncertainty as to the price to be paid for take or pay gas. The price considered by Pan-Alberta is $26.62/10^3m^3$ (75¢/Mcf) which represents in the main Pan-Alberta's contract price for gas as of November 1, 1975.

There are several factors which contribute to Pan-Alberta's difficulty in arranging suitable financing for its 1982/83 take or pay payments, if some other proposals, other than those being considered, are accepted. Since it is uncertain whether the effect of current pricing legislation would disallow the payment for gas not taken in sales contracts, an effective control over the incurrence of take or pay purchase obligations may be eliminated. As a result, it is apparent that take or pay will be a recurring problem in future years. This not only increases the amount of financing required in the long run, but also extends the term over which such financing would be required. The Commission has rendered a number of prior determinations approving the inclusion of take or pay carrying costs in the Alberta Cost of Service on an annual basis subject to providing the Commission each December with information to assess the continued necessity of maintaining the financing for take or pay payments and prudency of contract management. Presumably, approval of this Application would contain similar conditions. This creates uncertainty as to whether these costs will be recoverable in subsequent periods which in turn casts some doubt on Pan-Alberta's ability to service its long term debt. In addition, Pan-Alberta is not a utility with a large capitalization and therefore has limited capacity to attract financing.

The following example demonstrates the forecast impact of the inclusion of carrying costs for take or pay gas in Pan-Alberta's 1984 Alberta Cost of Service. It is assumed that take or pay payments would be made at 70.26¢/GJ (75¢/MMBtu) where the gas is assumed to be at 37.89 MJ/m^3 (1000 Btu/ft^3). Carrying costs on such payments have been estimated to be made at 11.125 percent per annum spread over annual purchases of 202.0 x 10^6 GJ (191.5 x 10^6 MMBtu). The following illustration assumes 100% of monies advanced:

Take or Pay Volume		821,353 10^3m^3
Amount Paid to Producers for Take or Pay Gas		$21,866,000
Annual Charge to Pan-Alberta's Alberta Cost of Service:		
Accrued Interest 83.12.31 to 84.02.29	$ 401,969	
Bank Loan Interest 84.03.01 to 84.12.31	$1,901,670	
Total Annual Charge		$ 2,303,639
Unit Cost of Gas Purchased by Pan-Alberta in Alberta		1.140¢/GJ

If producers receive take or pay payments to the same extent (11%) as they did in previous years, then the impact on Pan-Alberta's Alberta Cost of Service would reduce from 1.140¢/GJ to 0.128¢/GJ. When combined with the forecast effect of the 1977/78, 1978/79, 1979/80, 1980/81 and 1981/82 take or pay of 0.002, 0.005, 0.003, 0.111 and 0.053¢/GJ respectively, then the total impact of take or pay on Pan-Alberta's Cost of Service becomes 0.302¢/GJ.

2. Impact on Pan-Alberta

The approval of this request will improve the availability of the financing required by Pan-Alberta to pay for its take or pay obligations. The inclusion of carrying costs in the Alberta Cost of Service is critical to the continued financial viability of Pan-Alberta as Pan-Alberta would not be able to service the carrying costs by any other means.

Pan-Alberta has undertaken certain steps to limit take or pay obligations, however, these actions in themselves will not adequately arrest the take or pay problem. The Commission must recognize that the current pricing legislation has created the take or pay problem and that interim measures in the form of annual applications of this nature do not provide a satisfactory permanent solution.

F. PROPOSED PROCEDURES

Pan-Alberta proposes to obtain a separate and identifiable short term financing arrangement for the take or pay payments. The actual carrying costs associated with this special financing arrangement will be charged monthly to the Pan-Alberta Alberta Cost of Service.

Upon receiving approval from the Commission for recovering the carrying costs associated with take or pay payments, Pan-Alberta will make payments at a price of 70.26¢/GJ (75¢/MMBtu) in the form of an advance payment to those producers who accept this alternative. These payments would be based on the assumption that the take or pay gas was at 37.89 MJ/m^3 (1000 Btu/ft^3).

WHEREFORE Pan-Alberta respectively requests that the Commission grant expeditious approval of this Application dated at the City of Calgary, in the Province of Alberta, this 28th day of December, 1983.

Respectively submitted,

PAN-ALBERTA GAS LTD.

By____________________
R. J. Cradock
Vice-President, Operations

:lmb/0033B

Pan-Alberta Gas Ltd.

1984 01 13

Alberta Petroleum Marketing
Commission
Attention: Mr. T. Rayne
1900 Bow Valley Square IV
250 - 6th Avenue S. W.
Calgary, Alberta
T2P 3H7

Gentlemen:

Please find attached, a revised page 8 to our Application dated December 28, 1983. This page should be inserted into the original document replacing page 8.

Yours truly,

PAN-ALBERTA GAS LTD.

R. J. Cradock
Vice-President, Operations

WHW/spo
Attachment

RECEIVED
JAN 17 1984
ALBERTA PETROLEUM
MARKETING COMMISSION

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2. 1982/83 Contract Year Take or Pay

Calculations indicate that the take or pay obligat be in the order of 821 10^6m^3 (29.2 Bcf). In addition, ła has allocated this take or pay equally amongst all contracts e those where we have negotiated a reduced minimum annual volume ɔn and solution gas contracts.

Under the terms of Pan-Alberta's gas purchase (payments for take or pay gas are due sixty (60) days after ɔf the contract year in which the take or pay was incurred. Thers paid for but not taken during the 1982/83 contract year endi:r 31, 1983, will incur carrying costs commencing December 31, 198

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Pan-Alberta Gas Ltd.

ROUTE TO
Chairman
R.B. Hall
D.L. Willis
Admin. Asst.
G. Man. Finance
G. Man. E&P
G. Man. R. Gov
G. Man. Pol
Sec. & Sol
Sen. Advs. BD & CE
Auditor
W. McKay
T. Rousso
File
RETURN TO

1984.02.07

Alberta Petroleum Marketing Commission
Attention: Mr. V.M. Thomas
General Manager
1900, 250 - 6th Avenue S.W.
Calgary, Alberta
T2P 3H7

Dear Sir:

Re: Docket Number 84-01

Your letter of February 2, 1984 requested clarification as to the costs which Pan-Alberta would propose to recover in its Alberta cost of service in respect of its take or pay payments for the contract year ended October 31, 1983.

We advise that such costs would be comprised of the following components:

1. Interest:

   a) paid to the bank to service bank loans required to finance take or pay advance payments to Producers;

   b) paid to Producers on their respective advance payment amounts from the date such payments are due (December 31, 1983) to the date on which the company has in place the necessary bank financing, calculated at the prime lending rate in effect at the Bank of Montreal, Main Branch, Calgary;

2. Standby Charges paid to the bank on the undrawn portion of their credit committment for take or pay advance payments to Producers; and

3. Unrecoverable Producer repayments due under Pan-Alberta's take or pay advance payment arrangement.

RECEIV

FEB-3

ALBERTA PE
MARKETING CO ON

The Company is presently arranging financing with the Bank of Montreal for take or pay advance payments in respect of the contract year ended October 31, 1983. Upon receipt of an authorized line of credit from the Bank of Montreal, Pan-Alberta will advise the Commission of the cost rates applicable to items 1.a) and 2. above.

Yours truly,

PAN-ALBERTA GAS LTD.

G. Kaita
Treasurer

GK/kr

Pan-Alberta Gas Ltd.

DELIVERED BY HAND

1984 02 20

Alberta Petroleum Marketing Commission
Attention: Mr. V. M. Thomas
General Manager, Natural Gas
1900, 250 - 6th Avenue S.W.
Calgary, Alberta
T2P 3H7

Dear Sirs:

Re: Docket Number 84-01

Further to your letter of February 15, 1984, we advise that Pan-Alberta has arranged the following credits with the Bank of Montreal to finance its take or pay advance payments to Producers.

Credit Facility	Amount ($MM)	B of M Prime Plus: 1/8%	3/8%
1) Take or Pay #1 (renewal): Advance payments disbursed prior to 82.12.31; balance outstanding at 83.12.31	2.5	1982.03.01 to 1985.02.28	1985.03.01 to 1988.01.31
2) Take or Pay #2 (renewal): Advance payments disbursed during 1983; balance outstanding at 83.12.31	1.1	1983.03.01 to 1986.02.28	1986.03.01 to 1988.12.31
3) Take or Pay #3 (new): Potential advance payments to be disbursed during 1984; (1983 contract year - $22.2MM prior contract years - $14.3MM)	36.5	1984.03.01 to 1987.02.28	1987.03.01 to 1989.12.31

4) Overdue interest: at 1/2% above the foregoing interest rates.

5) Condition of lending: APMC approval for interest servicing in the Alberta cost of service equal to or greater than the foregoing interest rates during the full term of each credit.

With respect to the Take or Pay #3 Credit, the Standby Fee arrangements are as follows:

a) From date of availability to 1984.09.30:

- 1/8th of 1% on unused portion of $3.6MM (represents 1/80th of 1% if expressed in relation to total B of M commitment of $36.5MM).

b) 1984.10.01 to 1984.12.31:

- 1/8th of 1% on unused portion of $36.5MM.

We trust the foregoing will clarify items 1.a) and 2. of our letter of February 7, 1984.

Yours truly,

PAN-ALBERTA GAS LTD.

G. Kaita
Treasurer

GK/llt

ALBERTA PETROLEUM MARKETING COMMISSION

May 31, 1984

INFORMATION BULLETIN RE ALBERTA COST OF SERVICE

The Alberta Cost of Service Information Bulletin for the month of April, 1984 is attached.

The Information Bulletin consists of:

1. Copies of any special Orders or Determinations issued by the Commission during the month with respect to Alberta Cost of Service, and notice of any Statements of Objection which have been received during the month; and

2. Alberta Cost of Service Determinations for the month.

In the case of gas intended to be removed from Alberta, the cost of service determined under Section 11(1), 15(3)(a) and 15(5)(b)(i) of the Natural Gas Pricing Agreement Act for each month is based on estimated figures for that month, adjusted to allow for differences between the estimated and actual figures for the previous month.

In the case of gas intended for consumption within Alberta, the amount estimated as cost of service under Sections 11(2)(a)(ii) and 15(3)(b)(i) of the Act were made under the Commission's general directive for the Alberta cost of service.

All determinations are on gross or higher heating value on a dry basis at 15°C and an absolute pressure of 101.325 kPa (kilopascal).

Yours very truly,

ALBERTA PETROLEUM MARKETING COMMISSION

D. L. Willis
Vice-Chairman

Attachment

INFORMATION BULLETIN
ALBERTA COST OF SERVICE DETERMINATION
PURSUANT TO THE NATURAL GAS PRICING AGREEMENT ACT
MONTH OF APRIL, 1984

Section 15(3)(a)	Cents Per Gigajoule (GJ)*
Alberta and Southern Gas Co. Ltd.	
- Category A	44.079
- Category B	37.277
- Category E	31.152
Canadian Montana Pipe Line Company	49.697
Canadian Montana Gas Company Limited	49.683
Consolidated Natural Gas Limited	35.955
ICG Resources Ltd.	34.815
Many Islands Pipe Line (Canada) Limited	
- Purchased Gas	27.464
- North Sibbald (Agent)	2.949
- Saddle Lake	26.431
- Esther	11.134
Pan-Alberta Gas Ltd.	
- Basic	33.656
- Delivery Points - Leige	35.264
- Windy	71.851
- Lloydminster "B"	59.256
- Lloydminster "A"	64.406
- Fairydell-Bon Accord	35.465
Progas Limited	28.515
Societe quebecoise d'initiatives petrolieres (SOQUIP)	53.511
Sulpetro Limited	30.291
TransCanada PipeLines Limited	
- Average(1)	57.436
- Category A	58.178
- Category B1B2	58.244
- Category B1B3	59.845
- Category B1D2	54.290
- Category D1B2	33.653
- Category D1B3	35.117
- Category D1D2	29.711
- Category E	41.162
Westcoast Transmission Company	
- Husky Oil Ltd.	27.621
- Petrogas Processing Ltd. et al	28.239
Westcoast Transmission Company (Alberta) Limited	
- North	6.792
- Triassic E	.474

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<u>Section 15(3)(b)</u> 33.000

<u>Notes</u>

* Calculated on a gross and dry heating value basis at 101.325 kpa (kilopascal) and 15^{o}C.

<u>Notice</u>

The price adjustment for gas is $0.48/GJ
The Alberta Border Price is $2.790 01/GJ

(1) For purposes of sales within Alberta

DETERMINATION 84-13
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

REVIEW OF STATEMENTS OF OBJECTION

On February 24, 1984 Canterra Energy Ltd. (herein called the "Applicant") filed a statement of objection to the November 1983 Alberta cost of service determined for Consolidated Natural Gas Limited (herein called "Consolidated"). Further, on March 6, 1984 the Applicant filed a statement of objection to the December 1983 Alberta cost of service determined for Consolidated. The statements of objection are attached as Appendices "A" and "B".

The Commission elected to review the statements of objection and directed the Applicant to place a notice of each objection in two issues of "The Herald" in Calgary and "The Journal" in Edmonton. Copies of the statements of objection were required to be served on the Canadian Petroleum Association and the Independent Petroleum Association of Canada.

Consolidated and TransCanada PipeLines Limited filed a joint submission with respect to the statement of objection for the November Alberta cost of service in support of the Applicant.

DECISION

The Alberta costs of service determined for Consolidated for the months of November and December, 1983 are affirmed.

REASONS

The Commission has in Determination 84-12 (CNG) denied multi-tiered categories of Consolidated's Alberta cost of service.

DATED THIS 3rd day of May, 1984 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

APPENDIX "A"

IN THE MATTER of the Natural Gas Pricing Agreement Act and the Regulations thereunder; and

IN THE MATTER of the Alberta Cost of Service Determination for the Month of November, 1983

STATEMENT OF OBJECTION

CANTERRA ENERGY LTD. ("Canterra") hereby files a Statement of Objection pursuant to Section 6 of the Natural Gas Pricing Agreement Regulations (Alberta Regulation 127/77, as amended) made pursuant to the Natural Gas Pricing Agreement Act, S. A. 1975, c.38, as amended, with respect to the Alberta Cost of Service Determination made by the Alberta Petroleum Marketing Commission (the "Commission") for the month of November, 1983 (the "Determination").

Canterra is a party to a Gas Purchase Contract dated April 12, 1969 with Consolidated Natural Gas Limited ("Consolidated"), as amended ("the Contract"). There have been no payments made to Canterra for take or pay gas, as evidenced by the Affidavit set forth in Exhibit "A" attached hereto, either by Consolidated or Topcon Holdings Alberta Limited ("Topcon"), in respect of the contract years 1977/78 to 1982/83 inclusive.

Canterra objects that the cost of service allocated to gas sold pursuant to the Contract during November, 1983 was 42.724 cents per gigajoule, which is the cost of service established for all Consolidated contracts pursuant to the Determination. Pursuant to Determination 83-03 (CNG) and its subsequent amendment through Determination 83-05 (CNG) the Commission has determined that:

- interest payable by Consolidated to TransCanada PipeLines Limited ("TransCanada") on take or pay payments made by TransCanada to Consolidated, and paid by Consolidated to certain of its producers in respect of contract years 1977/78 to 1981/82 inclusive; and,

- interest costs of the 1983 Consolidated Allocation Program

shall be included in the Consolidated Alberta Cost of Service. Canterra understands that the amount so included in the November, 1983 Consolidated Alberta Cost of Service was 6.453 cents per gigajoule.

Since Canterra has not received take or pay payments from Consolidated or Topcon in respect of the contract years 1977/78 to 1982/83 inclusive and the Contract has been subject to reduced take or pay obligations by Consolidated in respect of the contract years 1980/81 to 1982/83 inclusive, and the Contract has been amended such that Consolidated's take or pay obligations for subsequent contract years have been reduced; Canterra requests that the Commission establish an additional category within the Consolidated Alberta Cost of Service to apply to the Contract, which category will not attract interest costs on take or pay payments, and Canterra requests that future Consolidated Alberta Cost of Service determinations should be adjusted to reimburse Canterra for interest costs on take or pay payments which have been included in Consolidated's Alberta Cost of Service since March, 1983, for all Consolidated contracts, including the Contract.

DATED at the City of Calgary this 24th day of February, 1984.

Respectfully submitted

CANTERRA ENERGY LTD.

M. L. Randall

M. L. Randall
Manager, Crude Oil &
Natural Gas Marketing

IN THE MATTER of the Natural Gas Pricing Agreement Act and the Regulations thereunder; and

IN THE MATTER of the Alberta Cost of Service Determination for the Month of December, 1983

STATEMENT OF OBJECTION

CANTERRA ENERGY LTD. ("Canterra") hereby files a Statement of Objection pursuant to Section 6 of the Natural Gas Pricing Agreement Regulations (Alberta Regulation 127/77, as amended) made pursuant to the Natural Gas Pricing Agreement Act, S. A. 1975, c.38, as amended, with respect to the Alberta Cost of Service Determination made by the Alberta Petroleum Marketing Commission (the "Commission") for the month of December, 1983 (the "Determination").

Canterra is a party to a Gas Purchase Contract dated April 12, 1969 with Consolidated Natural Gas Limited ("Consolidated"), as amended ("the Contract"). There have been no payments made to Canterra for take or pay gas, as evidenced by the Affidavit set forth in Exhibit "A" attached hereto, either by Consolidated or Topcon Holdings Alberta Limited ("Topcon"), in respect of the contract years 1977/78 to 1982/83 inclusive.

Canterra objects that the cost of service allocated to gas sold pursuant to the Contract during December, 1983 was 34.717 cents per gigajoule, which is the cost of service established for all Consolidated contracts pursuant to the Determination. Pursuant to Determination 83-03 (CNG) and its subsequent amendment through Determination 83-05 (CNG) the Commission has determined that:

- interest payable by Consolidated to TransCanada PipeLines Limited ("TransCanada") on take or pay payments made by TransCanada to Consolidated, and paid by Consolidated to certain of its producers in respect of contract years 1977/78 to 1981/82 inclusive; and,

- interest costs of the 1983 Consolidated Allocation Program

shall be included in the Consolidated Alberta Cost of Service. Canterra understands that the amount so included in the December, 1983 Consolidated Alberta Cost of Service was 6.082 cents per gigajoule.

Since Canterra has not received take or pay payments from Consolidated or Topcon in respect of the contract years 1977/78 to 1982/83 inclusive and the Contract has been subject to reduced take or pay obligations by Consolidated in respect of the contract years 1980/81 to 1982/83 inclusive, and the Contract has been amended such that Consolidated's take or pay obligations for subsequent contract years have been reduced; Canterra requests that the Commission establish an additional category within the Consolidated Alberta Cost of Service to apply to the Contract, which category will not attract interest costs on take or pay payments, and Canterra requests that future Consolidated Alberta Cost of Service determinations should be adjusted to reimburse Canterra for interest costs on take or pay payments which have been included in Consolidated's Alberta Cost of Service since March, 1983, for all Consolidated contracts, including the Contract.

DATED at the City of Calgary this 6th day of March, 1984.

Respectfully submitted

CANTERRA ENERGY LTD.

M. L. Randall

M. L. Randall
Manager, Crude Oil &
Natural Gas Marketing

DETERMINATION 84-14 (TCP)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

APPLICATION

By application dated April 13, 1984 TransCanada PipeLines Limited (TransCanada) applied to the Commission to include in its Alberta cost of service interest charges and other financing costs related to the third closing of the Topgas Two program. The application is attached hereto.

DECISION

The application is granted.

REASONS

The Commission considers that take or pay financing costs fall under the Natural Gas Pricing Agreement Regulation (A.R.119/82) as being "... considered just and reasonable by the Commission in respect of costs incurred by a person, whether or not the person is the original buyer, to finance payments made to or for the benefit of a producer in respect of gas not taken by the original buyer under a gas sales contract for which the producer was nevertheless entitled to be paid."

The Commission views this determination as an extension of Determination 83-09 (TCP).

DATED THIS 8th day of May, 1984 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

IN THE MATTER OF AN APPLICATION

BY TRANSCANADA PIPELINES LIMITED TO THE

ALBERTA PETROLEUM MARKETING COMMISSION

TO INCLUDE IN TRANSCANADA'S ALBERTA COST OF

SERVICE THE INTEREST COSTS OF TOPGAS TWO INC.

ARISING IN RESPECT OF THE FINANCING OF TAKE OR

PAY PAYMENTS TO BE MADE BY TOPGAS TWO INC.

ON MAY 31, 1984

April 13, 1984

PROVINCE OF ALBERTA

ALBERTA PETROLEUM MARKETING COMMISSION

APPLICATION TO INCLUDE IN TRANSCANADA'S ALBERTA COST OF SERVICE THE INTEREST COSTS OF TOPGAS TWO INC. ARISING IN RESPECT OF THE FINANCING OF TAKE OR PAY PAYMENTS TO BE MADE BY TOPGAS TWO INC. ON MAY 31, 1984

I. REQUEST

TransCanada PipeLines Limited ("TransCanada") requests that the Alberta Petroleum Marketing Commission ("the Commission") determine that from May 31, 1984 (the "Third Closing") until the end of the allocation period (as defined in the Topgas Two Agreement), it shall be just and reasonable to include and there shall be included in TransCanada's Alberta cost of service, interest at the rate of the Canadian Prime Rate (as defined in the Topgas Two Agreement) plus 7/8 of 1% in respect of the financing by Topgas Two Inc. ("Topgas Two") of payments to be made on May 31, 1984 by Topgas Two for gas available but not taken by TransCanada during the 1982/83 contract year.

TransCanada further requests that the Commission determine that it shall be just and reasonable to include and there shall be included in TransCanada's Alberta cost of service, additional financing and administration costs as described below, necessitated by the Third Closing of the Topgas Two Program.

II. THE TOPGAS TWO PROGRAM

TransCanada, Topgas Holdings Limited ("Topgas"), Topgas Two, and TransCanada's participating producers entered into an agreement, dated November 14, 1983, (the "Topgas Two Agreement") which provided for certain amendments to the 1982 allocation program as implemented through the agreements dated May 20, 1982, between TransCanada, Topgas and TransCanada's producers (the "Topgas Agreement"). The Topgas Two Agreement provided, among other things, that Topgas Two would make certain payments to TransCanada's producers in satisfaction of TransCanada's obligation to pay for gas available but not taken during the 1982/83 contract year. A copy of the Topgas Two Agreement was provided to the Commission as Exhibit "A" to TransCanada's application to the Commission dated November 16, 1983. The transactions contemplated under the Topgas Two Agreement were closed on December 30, 1983 (the "First Closing").

TransCanada, Topgas, Topgas Two and some of TransCanada's producers participated in another Closing under the Topgas Two Program on March 1, 1984 (the "Second Closing"). The details of the Second Closing were provided to the Commission in TransCanada's application dated February 16, 1984 (84-03 (TCP)). The Commission approved TransCanada's application in its Determination 84-03 (TCP). As at March 31, 1984, Topgas Two payments made to TransCanada's producers during the First and Second Closings were outstanding in the amount of $295,634,784.58 for take or pay gas.

III. THIRD CLOSING OF THE TOPGAS TWO PROGRAM

The Commission has requested in its Determination 84-03 (TCP) that TransCanada, Topgas and Topgas Two delay final closure of the Topgas Two Program until the costs of TransCanada's financing, outside of the Topgas Two program, have become known to the producers concerned. In response to this TransCanada, Topgas, and Topgas Two have agreed to a Third Closing under the Topgas Two Program which will occur on May 31, 1984. This Third Closing will be available to those producers who did not participate in either of the First or Second Closings but who may have received payment from TransCanada on December 30, 1983 for gas not taken by TransCanada during the 1982/83 contract year pursuant to the terms of the Topgas Agreement (such take or pay gas being referred to as "TransCanada Prepaid Gas").

Producers who intend to participate in the Third Closing are required to execute and return to TransCanada, Topgas Two Agreements together with a short letter of agreement (the "Third Closing Amending Agreement"), a copy of which is attached hereto as Exhibit "A". The Third Closing Amending Agreement provides for a closing during the month of May, 1984 and authorizes Topgas Two to advance funds to the credit of the producer at that time. Additionally, the Third Closing Amending Agreement provides for the return to TransCanada of those funds which TransCanada advanced to such producers on December 30, 1983, in respect of TransCanada Prepaid Gas.

At the date of this application, TransCanada has made payments in respect of 1982/83 TransCanada Prepaid Gas which are outstanding in the amount of $44,811,267.48 representing 21 860 729 gigajoules of prepaid gas.

To the extent that, on May 31, 1984, those producers who were not included in either of the First and Second Closing, choose to participate in the Topgas Two program, such TransCanada Prepaid Gas will cease to be outstanding on May 31, 1984 and, thereafter, there will be outstanding an equivalent amount of Topgas Two Prepaid Gas under the Topgas Two program which is in addition to the Topgas Two Prepaid Gas which was outstanding as of March 1, 1984. Topgas Two is obligated to pay to its Lenders interest at the rate of the Canadian Prime Rate plus 7/8 of 1% in respect of all advances made by its Lenders upon the Third Closing date.

IV. ADDITIONAL FINANCING COSTS

In TransCanada's application to the Commission dated November 16, 1983, TransCanada requested the recovery of certain financing and administration costs associated with the implementation and administration of the Topgas Two Program through its Alberta cost of service. These costs, described in detail on pages 13 through 15 of the said application, were submitted to the Commission as costs incurred to finance payments paid to producers by Topgas Two on December 30, 1983.

In TransCanada's application to the Commission dated February 16, 1983, TransCanada requested the recovery through its Alberta cost of service of certain additional financing and adminstration costs associated with the implementation of the Second Closing under the Topgas Two Program.

As a result of the agreement between TransCanada, Topgas and Topgas Two to offer a Third Closing under the Topgas Two Program, certain additional financing and administration costs associated with implementation of the Third Closing, will be payable by TransCanada.

These costs are:

(a) a stand-by fee, charged to Topgas Two in respect of funds committed by the banks to Topgas Two, but undrawn. This stand-by fee will be calculated as 1/4 of 1% per annum from March 1, 1984 until the date that such money is drawn by Topgas Two. TransCanada estimates that this stand-by fee will be in the order of $30,000.00.

(b) all other reasonable costs payable by Topgas Two to the Topgas Two syndicate and associated with the development and organization of the Third Closing including, without limiting the generality of such costs, the legal costs, engineering costs and printing costs arising out of the Third Closing. TransCanada proposes that from and including May 31, 1984 these additional financing and administration costs be included in TransCanada's Alberta cost of service.

V. Conclusion

Accordingly, TransCanada respectfully requests that the Commission determine that:

(a) from May 31, 1984, until the end of the allocation period, there shall be included in TransCanada's Alberta cost of service, interest at the rate of the Canadian Prime Rate plus 7/8 of 1% per annum in respect of the financing by Topgas Two of payments to be made on May 31, 1984 by Topgas Two in respect of gas available but not taken by TransCanada during the 1982/83 contract year; and

(b) that there shall be included in TransCanada's Alberta cost of service the additional financing and adminstration costs, as described above, necessitated by the Third Closing of the Topgas Two Program.

All of which is respectfully submitted

TRANSCANADA PIPELINES LIMITED

Per: ______________________

E.W.H. Mallabone
Manager, Legal

Communications related
to this Application
should be directed to:

Mr. E.W.H. Mallabone
Manager, Legal
TransCanada PipeLines Limited
TransCanada PipeLines Tower
530 - 8th Avenue S.W.
P.O. Box 500, Station M
Calgary, Alberta
T2P 3V6

EXHIBIT "A"

1984-04-02

(hereinafter referred to as "Seller")

Gentlemen:

This will refer to the agreement dated May 20, 1982 among TransCanada PipeLines Limited ("TransCanada"), Topgas Holdings Limited ("Topgas") and Seller, as the same heretofore may have been amended (the "Original Agreement"). Unless otherwise provided herein, all terms defined in the Original Agreement are used herein as so defined.

Pursuant to the Original Agreement, TransCanada paid to Seller or Seller's agent on December 30, 1983 an amount in respect of TransCanada Prepaid Gas incurred in the 1982/83 contract year.

TransCanada, Topgas, Topgas Two Inc. ("Topgas Two") and certain sellers of gas to TransCanada have entered into agreements dated November 14, 1983 (the "Topgas Two Producer Agreements") which provide, inter alia, for payments by Topgas Two in respect of gas available but not taken by TransCanada during the 1982/83 contract year and which would otherwise have constituted TransCanada Prepaid Gas. For the purposes of this agreement, those Seller's Gas Purchase Contracts (as defined in Seller's Topgas Two Producer Agreement) in respect of which Topgas Two did not make a payment on December 30, 1983 or March 1, 1984, and in respect of which each of the parties thereto has executed and delivered a Topgas Two Producer Agreement and an agreement substantially similar to this agreement and referred to as "Third Closing Gas Purchase Contracts".

As certain parties to some or all of Seller's Gas Purchase Contracts (as defined in the Original Agreement) did not execute and deliver a Topgas Two Producer Agreement prior to March 1, 1984, but have now done so, Seller wishes to enter into this agreement for the purpose of substituting payments by Topgas Two for payments made by TransCanada on December 30, 1983 in respect of TransCanada Prepaid Gas for the 1982/83 contract year.

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In consideration of Topgas and Topgas Two executing this agreement and any Topgas Two Producer Agreements which have not been previously executed and delivered and which amend any of Seller's Gas Purchase Contracts (as defined in the Original Agreement), the parties hereto agree as follows:

1. Seller hereby acknowledges that it or its agent received from TransCanada those payments set out in Exhibit "B" hereto in respect of TransCanada Prepaid Gas for the 1982/83 contract year incurred under each of the gas purchase contracts set forth in Exhibit "B".

2. Notwithstanding the provisions of paragraph 2A of Seller's Topgas Two Producer Agreement, the payment required to be made by Topgas Two with respect to each Third Closing Gas Purchase Contract shall be made on a date to be determined by TransCanada, which date shall be during the month of May, 1984 (the "Third Closing Date"), in lieu of December 30, 1983 as therein provided. On the Third Closing Date, Seller shall refund to TransCanada the amount of the payments received from TransCanada on December 30, 1983 in respect of each Third Closing Gas Purchase Contract by directing Topgas Two to pay to TransCanada the payments to be made by Topgas Two pursuant to paragraph 2A of Seller's Topgas Two Producer Agreement as amended by this Agreement and Seller hereby so directs.

3. Except for the purpose of determining for the period prior to the Third Closing Date the Alberta cost of service in respect of any Third Closing Gas Purchase Contract, upon receipt by TransCanada of the payments referred to in paragraph 2 hereof, TransCanada shall be deemed not to have incurred TransCanada Prepaid Gas in respect of the 1982/83 contract year in respect of any Third Closing Gas Purchase Agreement and Topgas Two Prepaid Gas (as defined in the Topgas Two Producer Agreement) under each Third Closing Gas Purchase Contract shall be deemed to have been outstanding as of December 31, 1983.

4. Except as otherwise expressly provided for herein, Seller's

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Topgas Two Producer Agreement is hereby confirmed.

TRANSCANADA PIPELINES LIMITED

Per: ______________________________
Vice President

Per: ________________________c/s

AGREED AND ACCEPTED the _____ day of ______________, 1984

TOPGAS HOLDINGS LIMITED

Per: ________________________c/s

TOPGAS TWO INC.

Per: ________________________c/s

AGREED AND ACCEPTED BY SELLER the _______ day of ______________, 1984.

SELLER (Print in Seller's Name)

____

Per: ______________________________

Per: ______________________________

Affix Corporate Seal

DETERMINATION 84-15
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

REVIEW OF STATEMENT OF OBJECTION

On March 20, 1984, Signalta Resources Ltd. (herein called the "Applicant") filed a statement of objection to the December 1983 Alberta cost of service determined for TransCanada PipeLines Limited (herein called "TransCanada"). The statement of objection is attached as Appendix "A".

The Commission elected to review the statement of objection and directed the Applicant to place a notice of the objection in two consecutive issues of "The Herald" in Calgary and "The Journal" in Edmonton, on or before March 31, 1984 and to serve a copy on the Canadian Petroleum Association and Independent Petroleum Association of Canada on or before March 28, 1984.

TransCanada filed a submission in support of the statement of objection.

DECISION

The Alberta cost of service determined for TransCanada for the month of December 1983 is affirmed.

REASONS

The issue in the statement of objection is whether gas delivered under the Applicant's gas purchase contract should be free of Topgas Two interest costs because the applicant has not received take or pay payments under the Topgas Two program.

In Determination 83-10 (TCP) the Commission established sub-category D_2 for gas purchase contracts amended by the Topgas Two Agreement as to which producers entitled to take or pay payments waived the payments or repaid the payments in full after December 30, 1983. The Applicant's gas purchase contract is amended by the Topgas Two Agreement but no take or pay payments were payable for the 1982/83 contract year.

The issue posed by the Applicant parallels the issue decided by the Commission in Determination 84-05 in which the Commission states that it does not propose to extend the limits of eligibility for Category D.

DATED THIS 18th day of May, 1984 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

APPENDIX "A"

IN THE MATTER OF THE NATURAL GAS PRICING AGREEMENT ACT AND THE REGULATIONS THEREUNDER;

AND IN THE MATTER OF THE ALBERTA COST OF SERVICE DETERMINATION FOR THE MONTH OF DECEMBER, 1983.

STATEMENT OF OBJECTION

SIGNALTA RESOURCES LTD. ("Signalta") hereby files a Statement of Objection pursuant to Section 6 of the Natural Gas Pricing Agreement Regulations (Alberta Regulation 307/80, as amended) made pursuant to the Natural Gas Pricing Agreement Act, S.A. 1975, c. 38, as amended (now R.S.A. 1980, c. N-3), with respect to the Alberta Cost of Service Determination made by the Petroleum Marketing Commission (the "Commission") on January 23, 1984 for the month of December, 1983 (the "Determination").

Signalta is a party to a Gas Purchase Contract dated December 20, 1977, with TransCanada Pipelines Limited ("TCPL"), as amended (the "Contract"). Gas sales commenced pursuant to the Contract during the 1978/79 contract year and Signalta received payments for take-or-pay gas during the 1978/79, 1979/80 and 1980/81 contract years. Signalta executed the Topgas Agreement dated May 20, 1982 (the "Topgas One Agreement"), and elected to repay to TCPL all monies previously received by way of prepayments and waived or repaid any further payments for take-or-pay gas to which it was entitled under the Topgas program. All prepayments have been repaid and no further payments under the Topgas program have been received by Signalta. Signalta subsequently executed the Topgas Two Agreement on November 21, 1983. At all times since implementation of the market allocation program by TCPL, Signalta has submitted to such program and its gas deliveries have been subject to its proportionate share of the market allocation.

As a result of Signalta executing the Topgas One Agreement and as a result of Signalta's delivery levels during the 1981/82 and the 1982/83 contract years, prepayments were not made to Signalta for the 1982/83 contract year. However, we wish to make it clear that Signalta executed the waiver document attached to the Topgas Two Agreement evidencing its intention to waive any prepayments to which it might have been entitled under the Topgas Two program. Attached as Exhibit "A" is an Affidavit of Gordon M. Bradford, Treasurer of Signalta, deposing to the above facts.

Signalta objects that the cost of service allocated to gas sold by it pursuant to the Contract during December, 1983 was 28.5630 cents per gigajoule, which is the cost of service for Category D_1B_2 as established by Commission Determination 83-10 (TCP).

Signalta has been informed by the Commission that Category D_2 was intended to include only those gas purchase contracts amended by the Topgas Two Agreement where producers actually entitled to take-or-pay payments under the Topgas Two Agreement have waived their payments or repaid their payments in full after December 30, 1983. Since Signalta was not in a position to receive Topgas Two prepayments its waiver of such prepayments was ineffective and its contract has been placed in the D_1B_2 Category.

The principles upon which the categories were established by Determination 83-10 (TCP) are reported to be the same as followed in Determination 82-14 (TCP) and, in particular, that:

> "The Commission considers it just and reasonable to require separate categories of Alberta cost of service in order to more fairly assess the costs of take or pay

> financing against the beneficiaries of take or pay payments." (Determination 82-14 (TCP) p. 10)

This principle appears to at least partially recognize the recommendation of the Alberta Public Utilities Board that the "costs of 'take-or-pay' advances not form part of the ACOS but be borne by those producers who receive such advances." (see Public Utilities Board, Alberta - Alberta Cost of Service Inquiry - Report No. E 78100 - June 30, 1978).

In a subsequent determination, Determination 83-06 (TCP), the Commission commented that:

> "The Topgas program substantially altered TransCanada's take or pay obligations to the Topgas participants, and the costs and method of financing those obligations. The Commission viewed the resulting divergence between take or pay rights and obligations of Topgas participants and non-participants together with the additional payments received by the participants under the Topgas program as factors warranting the decision in determination 82-14 (TCP) to accept TransCanada's proposal for a multi-tiered Alberta cost of service for take or pay financing costs". (Determination 83-06 (TCP), p. 1)

With respect to Category D the Commission indicated that:

> "[This Category] was established for Topgas participants for the limited purpose of inducing a voluntary reduction in the amount of take or pay payments outstanding under Categories B and C contracts after the implementation date of the Topgas program." (Determination 83-06 (TCP), p. 2)

This concept was repeated in Determination 83-10 (TCP) wherein the Commission stated that:

> "Sub-categories D_1 and D_2 are established for the limited purpose of inducing a further voluntary reduction in the amount of take or pay payments outstanding."

It is Signalta's position that in certain situations the establishment of Category D for the limited purpose of inducing a voluntary reduction of prepayment amounts is inconsistent with the principle that it is just and reasonable to assess the costs of take-or-pay financing against the beneficiaries of take-or-pay payments. Signalta submits that the latter principle should be the overriding one.

Signalta's Contract has been amended by the Topgas One Agreement and the Topgas Two Agreement. At all times Signalta has accepted the market allocation plan as implemented by TCPL. At the earliest opportunity Signalta repaid all prepayment amounts which it had received and, when possible, has waived any further prepayments under the Topgas program. Accordingly, Signalta submits that its Contract should be properly included within Category D_1D_2 and that the cost of service allocated during December, 1983 should be 26.4820 cents per gigajoule rather the 28.5630 cents per gigajoule which was allocated.

It is not just or reasonable to impose a cost of service which includes take-or-pay interest costs when Signalta has done everything within its power to avoid prepayments and has cooperated to the fullest extent possible with the Topgas program and the market allocation plan. To include the Signalta Contract in Category D_1B_2 is contrary to the stated principle of the Commission to fairly assess the costs of take-or-pay interest costs against the beneficiaries of take-or-pay payments.

In addition, Signalta submits that the Commission has exceeded the jurisdiction granted to it pursuant to the Natural

Gas Pricing Agreement Act by establishing Categories D_1 and D_2 for the limited purpose of inducing a voluntary reduction in the amount of take-or-pay payments outstanding after the implementation date of the Topgas programs. It is submitted that a producer with a gas purchase contract amended by the Topgas One Agreement and the Topgas Two Agreement, which has, at all times, been subject to the market allocation program and which has repaid and/or waived any prepayment amounts received under its contract, should not be subject to a cost of service which includes interest costs of take-or-pay payments.

Accordingly, Signalta requests that the Contract be included within Category D_1D_2 and that appropriate adjustments be made so that the cost of service allocated to all gas sold pursuant to the Contract during December, 1983 is 26.4820 cents per gigajoule rather than 28.5630 cents per gigajoule and that all allocations of cost of service to the Contract thereafter be those determined in respect to contracts within Category D_1D_2.

DATED at the City of Calgary this 20th day of March, 1984.

Respectively Submitted

JAMES B. McCASHIN
Counsel for Signalta

Signalta's address for all purposes hereunder is as follows:

Atkinson McMahon
1900, 350 - 7th Avenue S.W.
Calgary, Alberta
T2P 3N9

Attention: J. B. McCashin

Exhibit "A"

Affidavit

Canada)
)
Province of Alberta)
)
TO WIT:)

I, Gordon M. Bradford, of the City of Calgary, in the Province of Alberta, MAKE OATH AND SAY THAT:

1. I am Treasurer of Signalta Resources Ltd. ("Signalta"), a corporation registered to do business in the Province of Alberta.

2. Signalta is a party to a Gas Purchase Contract with TransCanada Pipelines Limited ("TCPL") dated December 20, 1977.

3. As of the date hereof, Signalta has repaid and/or waived all take-or-pay payments pursuant to the aforesaid contract and does not now have any prepaid gas under the said contract.

SWORN BEFORE ME at the City of Calgary, in the Province of Alberta, this 20 day of March, 1984.)

B A Clarke

A Commissioner for Oaths in and for the Province of Alberta.

BEVERLEY A. CLARKE
Appointment Expires 4/28/84

GORDON M. BRADFORD

DETERMINATION 84-16
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

REVIEW OF STATEMENT OF OBJECTION

On March 28, 1984, Sulpetro Limited (herein called the "Applicant") filed a statement of objection to the January 1984 Alberta cost of service determined for TransCanada PipeLines Limited (herein called "TransCanada"). The statement of objection is attached as Appendix "A".

The Commission elected to review the statement of objection and directed the Applicant to place a notice of the objection in two consecutive issues of "The Herald" in Calgary and "The Journal" in Edmonton, on or before April 10, 1984 and to serve a copy on the Canadian Petroleum Association and Independent Petroleum Association of Canada on or before April 6, 1984.

DECISION

The Alberta cost of service determined for TransCanada for the month of January 1984 is affirmed.

REASONS

The issue in the statement of objection is whether gas delivered under the Applicant's gas purchase contract should be free of Topgas Two financing costs because the applicant has not received take or pay payments under the Topgas Two program.

In Determination 83-10 (TCP) the Commission established sub-category D_2 for gas purchase contracts amended by the Topgas Two Agreement as to which producers entitled to take or pay payments waived the payments or repaid the payments in full after December 30, 1983. The Applicant's gas purchase contract is amended by the Topgas Two Agreement but no take or pay payments were payable for the 1982/83 contract year.

A request to extend the limits of eligibility for Category D was dealt with in Determination 84-05. The issue posed by the Applicant parallels the issue decided by the Commission in Determination 84-05 in which the Commission states that it does not propose to extend the limits of eligibility for Category D.

DATED THIS 18th day of May, 1984 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

APPENDIX "A"

PROVINCE OF ALBERTA
ALBERTA PETROLEUM MARKETING COMMISSION

RE: OBJECTION TO ALBERTA PETROLEUM MARKETING COMMISSION INFORMATION BULLETIN DATED FEBRUARY 29, 1984 (Alberta Cost of Service - January 1984)

1. Pursuant to Section 6 of The Natural Gas Pricing Agreement Regulations, Sulpetro Limited ("Sulpetro") objects to the determination by the Alberta Petroleum Marketing Commission ("APMC") of the Alberta cost of service for the month of January 1984 as it pertains to natural gas sales by Sulpetro to TransCanada PipeLines Limited ("TCPL") in the Wapiti, Alberta area.

2. Sulpetro is a producer of natural gas in the Wapiti area. In this objection, Sulpetro is acting on behalf of itself and the other producers named in the TCPL contract dated October 27, 1976 covering the Wapiti area (the "Contract").

3. Specifically, Sulpetro objects to the application of the B_1B_2 Alberta cost of service category to the Contract and submits that the appropriate categorization should be B_1D_2.

4. Sulpetro notes that the APMC cost of service for January 1984 arises from APMC Determination 83-10 (TCP) dated December 9, 1983 stipulating that "Sub-category D_2 shall consist of gas purchase contracts amended by the Topgas Two Agreement under which producers actually entitled to take or pay payments have waived the payments or repaid the payments in full after December 30, 1983". Sulpetro does not waive any right of appeal it may have in respect of Determination 83-10 (TCP) by virtue of this objection.

5. The Contract is a reserves type contract pursuant to which the Producer is entitled to increase the reserve base by development of the contracted area.

6. The Topgas Agreements amended the Contract to provide that take or pay payments would be based on 60% of the 1981/82 reserves, but the allocation portion of those Agreements tied TCPL's obligation to purchase gas from the Contract to the most recent contract reserve. As a result, deliveries during 1982/83 which were calculated on the Contract's 1982/83 reserve base exceeded the threshhold level for take or pay payments which were based on the lower 1981/82 contract reserve level. Under this pattern of nominations and deliveries, Sulpetro and its partners did not receive any more proportional delivery benefits under the Contract than did any other contract selling to TCPL.

7. Sulpetro realized when it signed the Topgas Two Agreement that it would not receive take or pay monies under the Contract for the 1982/83 contract year but it did not anticipate that the Contract would nevertheless bear the burden of the Topgas Two carrying costs as a component of the applicable cost of service.

8. Sulpetro submits that it is inequitable that the Contract, which has not received the benefits of any take or pay payments under the Topgas Two Agreement should bear a portion of the cost of the Topgas Two program in the Alberta cost of service.

DATED at the City of Calgary, Alberta, this 23rd day of March, 1984.

Respectfully submitted,
SULPETRO LIMITED

Per: ______________________

DCF*vw

Alberta PETROLEUM MARKETING COMMISSION

DETERMINATION 84-17 (CNG)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

APPLICATION

By application dated October 17, 1983, Consolidated Natural Gas Limited (Consolidated) requests that the Commission amend Determination 83-05 (CNG) to include in its Alberta cost of service the management fee and administrative costs associated with the 1983 Consolidated Allocation Program. The application (without exhibits) is attached as "Appendix A" and Determination 83-05 (CNG) is attached as "Appendix B" (without appendices).

DECISION

Determination 83-05 (CNG) is amended as follows:

Paragraph no. 2 is deleted and the following substituted therefor:

2. Add as paragraph no. 4 the following:

"4. a) Interest costs of the 1983 Consolidated Allocation Program are allowed in Alberta cost of service.

b) The financing and administration costs of the 1983 Consolidated Allocation Program as applied for in the application dated October 17, 1983 are allowed in Alberta cost of service as incurred."

REASONS

The financing and administration costs of the 1983 Consolidated Allocation Program are actual costs which the Commission considers to qualify under the Natural Gas Pricing Agreement Amendment Regulation (A.R.119/82) as being "...considered just and reasonable by the Commission in respect of costs incurred by a person, whether or not the person is the original buyer, to finance payments made to or for the benefit of a producer in respect of gas not taken by the original buyer under a gas sales contract for which the producer was nevertheless entitled to be paid."

DATED THIS 28th day of May, 1984 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

APPENDIX "A"

PROVINCE OF ALBERTA

ALBERTA PETROLEUM MARKETING COMMISSION

APPLICATION BY CONSOLIDATED NATURAL GAS LIMITED TO AMEND

COMMISSION DETERMINATION 83-05 (CNG)

TO INCLUDE IN AN ALBERTA COST OF SERVICE

THE MANAGEMENT FEE AND ADMINISTRATIVE COSTS ASSOCIATED WITH THE 1983

CONSOLIDATED ALLOCATION PROGRAM

I. REQUEST

Consolidated Natural Gas Limited ("Consolidated") requests the Alberta Petroleum Marketing Commission ("Commission") to amend Commission Determination 83-05 (CNG) as follows:

(a) to include in Consolidated's Alberta Cost of Service an amount equal to the amount of the Management Fee which Topcon Holdings Alberta Limited ("Topcon") is required to pay to the Canadian Imperial Bank of Commerce ("Bank") and which Consolidated is required to reimburse to Topcon;

(b) to include in Consolidated's Alberta cost of service an amount equal to the amount of the costs and expenses incurred by Topcon in connection with the Topcon Allocation Agreement described on page 3 of this application which Consolidated is required to pay to Topcon; and

(c) to include in Consolidated's Alberta cost of service an amount equal to Topcon's administrative and operating costs.

II PRESENT PRACTICE

A Management Fee of $200,000.00 is payable by Topcon to the Bank pursuant to Article 5.2 of the Loan Agreement dated July 27, 1983 between Topcon and the Bank. A copy of the Loan Agreement is filed under Tab 1 of this Application. Consolidated is obligated to pay to Topcon an amount equal to the Management

Fee of $200,000.00 by virtue of subsection 5.5 (b) of the Memorandum of Agreement ("Memorandum of Agreement") dated July 25, 1983 among Consolidated, TransCanada PipeLines Limited and Topcon. A copy of the Memorandum of Agreement is filed under Tab 2 of this Application. Consolidated had originally anticipated that the Management Fee would be 1/2 of 1% of the funds advanced by Topcon. However, on August 4, 1983 it was agreed that the Management Fee would be $200,000.00.

Pursuant to subsection 5.5 (d) of the Memorandum of Agreement, Consolidated is obligated to reimburse Topcon for its reasonable costs and expenses in respect of the Memorandum of Agreement, the Loan Agreement, the Producer Agreement (as defined in the Memorandum of Agreement) and the transactions contemplated thereby. Section 5.4 of the Loan Agreement obligates Topcon to reimburse the Bank for its reasonable costs, charges and expenses in respect of the Loan Agreement, the Memorandum of Agreement and the Producer Agreement and the transactions contemplated thereby. Subsection 5.5 (d) of the Memorandum of Agreement obligates Consolidated to reimburse Topcon for the amounts which Topcon is required to pay the Bank pursuant to section 5.4 of the Loan Agreement.

Subsection 5.5 (e) of the Memorandum of Agreement requires Consolidated to pay to Topcon an amount sufficient to enable Topcon to pay all of the reasonable administrative, operating and other similar costs and expenses incurred by Topcon.

The Loan Agreement and the Memorandum Agreement were not finalized until after Commission Determinations 83-03 (CNG) and 83-05 (CNG) were issued.

III PROPOSED AMENDMENT TO COMMISSION DETERMINATION 83-05 (CNG)

Consolidated proposes that Commission Determination 83-05 (CNG) be amended after paragraph 4 (b) as follows:

(a) by deleting paragraph 4 (b) and inserting in its place the following:

"4 (b) the financing and administration costs of the 1983 Consolidated Allocation Program as applied for in Consolidated's application to the Commission dated July 2, 1983 other than the Management Fee are allowed to be recovered as incurred through Consolidated's Alberta cost of service."

(b) by adding after the said paragraph 4 (b) the following paragraphs 4 (c), 4 (d) and 4 (e):

4(c) "the amount which Consolidated is required to pay Topcon pursuant to subsection 5.5 (b) of the Memorandum of Agreement and which is equal to the Management Fee of $200,000.00 which Topcon is required to pay to the Bank be allowed to be recovered, as incurred, through Consolidated's Alberta cost of service;

(d) the amount which Consolidated is required to pay Topcon pursuant to subsection 5.5 (d) of the Memorandum of Agreement and which is equal to the costs and expenses incurred in connection with the 1983 Consolidation Allocation Program (including costs and expenses incurred by the Bank which Topcon is required to reimburse to the Bank) be allowed to be recovered, as incurred, through Consolidated's Alberta cost of service.

(e) the amount which Consolidated is required to pay to Topcon pursuant to subsection 5.5 (e) of the Memorandum of Agreement and which is an amount sufficient to enable Topcon to pay its reasonable administrative, operating and other similar costs and expenses be allowed to be recovered, as incurred, through Consolidated's Alberta cost of service."

IV ANTICIPATED EFFECT ON CONSOLIDATED's ALBERTA COST OF SERVICE

Consolidated's Alberta cost of service will not be affected significantly by the proposed amendment.

V ANTICIPATED EFFECT ON THE APPLICANT

No effect is anticipated on Consolidated because of the flow-through nature of the payments.

VI ANTICIPATED EFFECT ON THIRD PARTIES

The Management Fee and administrative costs recovered by Consolidated through Consolidated's Alberta cost of service will be forwarded to Topcon as reimbursement for the actual Management Fee and administrative costs incurred by Topcon.

VII CONCLUSION

Consolidated respectfully requests the Commission to amend Commission Determination 83-05 (CNG) to determine that:

There shall be included in Consolidated's Alberta cost of service for repayment to Topcon the Management Fee and administrative costs as described in Part III herein.

Dated at the City of Calgary, in the Province of Alberta, this 17th day of October, 1983.

ALL OF WHICH IS RESPECTFULLY SUBMITTED
CONSOLIDATED NATURAL GAS LIMITED

W.J. DEMCOE
VICE PRESIDENT FINANCE AND SECRETARY

APPENDIX "B"

DETERMINATION 83-05 (CNG)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

APPLICATION

By application dated June 2, 1983, Consolidated Natural Gas Limited (Consolidated) requests that the Commission amend Determination 83-03 (CNG) to include in its Alberta cost of service costs of a program referred to as the "1983 Consolidated Allocation Program" to finance take or pay payments. The application (except exhibits) is shown in the attached Appendix "A". Determination 83-03 (CNG) is shown as Appendix "B".

Interest costs will be at the rate per annum of 7/8 of 1% plus the annual rate of interest equal to the rate of interest quoted or published by the Canadian Imperial Bank of Commerce from time to time as being its prime rate of interest for Canadian dollar loans made in Canada.

DECISION

Determination 83-03 (CNG) is amended as follows:

1. Delete subparagraphs b) and c) of paragraph no. 1 of the Decision.

2. Add as paragraph no. 4 the following:

"4. a) Interest costs of the 1983 Consolidated Allocation Program are allowed in Alberta cost of service.

b) The financing and administration costs of the 1983 Consolidated Allocation Program as applied for, are allowed to be recovered as incurred through Alberta cost of service."

.../2

REASONS

The Commission views the 1983 Consolidated Allocation Program to be an appropriate method of financing take or pay obligations which qualifies under the Natural Gas Pricing Agreement Amendment Regulation (A.R.119/82) as being "...considered just and reasonable by the Commission in respect of costs incurred by a person, whether or not the person is the original buyer, to finance payments made to or for the benefit of a producer in respect of gas not taken by the original buyer under a gas sales contract for which the producer was nevertheless entitled to be paid."

DATED THIS 22nd day of July, 1983 at Calgary, Alberta.

D. C. Hetland
Secretary and Solicitor

PETROLEUM MARKETING COMMISSION

June 29, 1984

INFORMATION BULLETIN RE ALBERTA COST OF SERVICE

The Alberta Cost of Service Information Bulletin for the month of May, 1984 is attached.

The Information Bulletin consists of:

1. Copies of any special Orders or Determinations issued by the Commission during the month with respect to Alberta Cost of Service, and notice of any Statements of Objection which have been received during the month; and

2. Alberta Cost of Service Determinations for the month.

In the case of gas intended to be removed from Alberta, the cost of service determined under Section 11(1), 15(3)(a) and 15(5)(b)(i) of the Natural Gas Pricing Agreement Act for each month is based on estimated figures for that month, adjusted to allow for differences between the estimated and actual figures for the previous month.

In the case of gas intended for consumption within Alberta, the amount estimated as cost of service under Sections 11(2)(a)(ii) and 15(3)(b)(i) of the Act were made under the Commission's general directive for the Alberta cost of service.

All determinations are on gross or higher heating value on a dry basis at 15°C and an absolute pressure of 101.325 kPa (kilopascal).

Yours very truly,

ALBERTA PETROLEUM MARKETING COMMISSION

D. L. Willis
Vice-Chairman

Attachment

INFORMATION BULLETIN
ALBERTA COST OF SERVICE DETERMINATION
PURSUANT TO THE NATURAL GAS PRICING AGREEMENT ACT
MONTH OF MAY, 1984

Section 15(3)(a)	Cents Per Gigajoule (GJ)*
Alberta and Southern Gas Co. Ltd.	
- Category A	87.831
- Category B	36.471
- Category E	28.806
Canadian Montana Pipe Line Company	50.527
Canadian Montana Gas Company Limited	50.549
Consolidated Natural Gas Limited	51.167
ICG Resources Ltd.	42.653
Many Islands Pipe Line (Canada) Limited	
- Purchased Gas	27.205
- North Sibbald (Agent)	10.037
- Saddle Lake	35.428
- Esther	15.783
Pan-Alberta Gas Ltd.	
- Basic	36.211
- Delivery Point - Leige	37.818
Progas Limited	35.373
Societe quebecoise d'initiatives petrolieres (SOQUIP)	39.461
Sulpetro Limited	37.976
TransCanada PipeLines Limited	
- Average(1)	55.441
- Category A	56.855
- Category B1B2	55.968
- Category B1B3	60.562
- Category B1D2	51.876
- Category D1B2	29.807
- Category D1B3	34.279
- Category D1D2	25.392
- Category E	40.082
Westcoast Transmission Company	
- Husky Oil Ltd.	30.319
- Petrogas Processing Ltd. et al	33.444
Westcoast Transmission Company (Alberta) Limited	
- North	32.024
- Triassic E	.474

<u>Section 15(3)(b)</u> 33.000

.../2

Notes

* Calculated on a gross and dry heating value basis at 101.325 kpa (kilopascal) and 15°C.

Notice

The price adjustment for gas is $0.48/GJ
The Alberta Border Price is $2.790 01/GJ

(1) For purposes of sales within Alberta

DETERMINATION 84-18 (TCP)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

APPLICATION

By application dated February 29, 1984, TransCanada PipeLines Limited (TransCanada) requests approval for inclusion in Alberta cost of service the cost of capital in respect of financing of take or pay payments made by TransCanada under Category E contracts and for TransCanada Prepaid Gas incurred during the 1982/83 contract year.

In its application, TransCanada requests a capital structure which approximates that approved by the National Energy Board (the Board) in its June 1983 Reasons for Decision: 60% debt, 12% preferred equity, and 28% common equity. TransCanada has requested current market rates for debt and preferred equity and the rate of return on common equity as approved by the Board from time to time. The application is attached as Appendix "A".

DECISION

1. A combination of debt and equity financing of take or pay payments is allowed.
2. The cost of capital for financing take or pay payments shall be the rate of return on TransCanada's Alberta rate base plus an allowance for income taxes, as approved by the Commission from time to time.
3. This determination is effective from May 1, 1984.

REASONS

Prior to the Topgas program, the Commission allowed debt/equity financing for TransCanada's take or pay payments.

The Commission considers financing requirements for the take or pay payments to be similar to the financing requirements for Alberta rate base assets. The restrictions in the Topgas program require that the take or pay payments must remain outstanding for a minimum of five years and it is estimated by TransCanada to be required over a ten to fifteen year period. In the case of take or pay payments under Category E contracts, the financing is estimated by TransCanada to be required over a five to nine year period. Accordingly, the cost of financing should be consistent with the cost of capital as allowed for TransCanada's Alberta rate base. Determination 83-08 (TCP) prescribes the present rate and is attached as Appendix "B".

DATED this 8th day of June, 1984 at Calgary, Alberta.

M R Pullam

M. R. Pullam
Acting Secretary

APPENDIX "A"

PROVINCE OF ALBERTA
ALBERTA PETROLEUM MARKETING COMMISSION

Application to include carrying costs arising from permanent financing by TransCanada PipeLines Limited of TransCanada Prepaid Gas incurred during the 1982/83 contract year and take or pay gas outstanding under Category E contracts.

PROVINCE OF ALBERTA
ALBERTA PETROLEUM MARKETING COMMISSION

Application to include carrying costs arising from permanent financing by TransCanada PipeLines Limited of TransCanada Prepaid Gas incurred during the 1982/83 contract year and take or pay gas outstanding under Category E contracts.

I. Request

TransCanada PipeLines Limited ("TransCanada") requests that the Alberta Petroleum Marketing Commission ("the Commission") determine that on and from May 1, 1984 it shall be just and reasonable to include and there shall be included in TransCanada's Alberta cost of service the cost of capital of TransCanada, as described herein, in respect of the financing of take or pay payments made by TransCanada under Category E contracts (as defined below) and for TransCanada Prepaid Gas (as defined below) incurred during the 1982/83 contract year, and that the inclusion of such costs in TransCanada's Alberta cost of service continue until the recovery by TransCanada of all such gas.

II. Status of Take or Pay Under TransCanada's Gas Purchase Contracts

In October, 1982, TransCanada, its producers and Topgas Holdings Limited ("Topgas") entered into an agreement (the "Topgas Agreement") whereby Topgas paid to TransCanada's producers approximately $2.3 billion in respect of gas available but not taken by TransCanada

during the contract years 1976/77 through 1981/82. Monies previously paid to producers in respect of such gas were returned to TransCanada. Upon Closing of the transactions contemplated under the Topgas Agreement, TransCanada had a remaining outstanding take or pay balance in respect of those of its gas purchase contracts which were not amended by the Topgas Agreement ("Category E Contracts") in the amount of $6.5 million.

Under the Topgas Agreement, TransCanada's producers agreed to a reduction in the level of TransCanada's take or pay obligation to 60% of the 1980/81 minimum annual obligation under each gas purchase contract. TransCanada agreed to equitably allocate its annual market available for allocation to its allocable gas purchase contracts.

During the 1982/83 contract year and as a result of adverse market conditions (recession, warm weather, etc.), TransCanada took a volume of gas under its allocable gas purchase contracts equal to 47% of the collective minimum annual obligations thereunder and was obligated, under paragraph 6 of the Topgas Agreement, to make take or pay payments to its producers in the approximate amount of $365 million for the gas not taken (defined in the Topgas Agreement as "TransCanada Prepaid Gas"). Because the recovery period for such TransCanada Prepaid Gas does not commence until Topgas has fully recovered the advances which it made to producers and because of the uncertainties associated with this extended period, TransCanada determined that it

could only finance such payments at a relatively high cost. Accordingly, TransCanada entered into an agreement (the "Topgas Two Agreement") with Topgas Two Inc. ("Topgas Two") whereby Topgas Two agreed to discharge TransCanada's 1982/83 obligation to producers. Under this Agreement, Topgas agreed that Topgas Two could recover its advances to producers concurrently with those advances made by Topgas under the Topgas Agreement, such recovery to occur over a maximum ten year term commencing on November 1, 1984. Interest costs on 1982/83 take or pay advances would therefore accrue on a balance which would decline from November 1, 1984, and at substantially lower rates than TransCanada could have obtained in financing its obligation on its own balance sheet.

In addition to allowing payments by Topgas Two, the Topgas Two Agreement reduced TransCanada's take or pay obligation level to 50% of the 1981/82 obligation level, with provision for such level to rise to 60% with the increase of TransCanada's markets. This amendment to the Topgas Agreement reduces the risk that TransCanada will incur future take or pay.

On December 30, 1983, TransCanada, Topgas, Topgas Two Inc. and participating producers completed the 1st Closing under the Topgas Two Agreement. At that time, $275 million was paid to producers by Topgas Two. TransCanada, Topgas, Topgas Two and subsequently participating producers will complete a 2nd Closing on March 1. On the basis of documentation received, TransCanada anticipates that Topgas Two will

make a further payment of $32 million to TransCanada's producers, of which $1.7 million represents an adjustment amount from the 1st Closing. Upon this 2nd Closing, producers representing approximately 90% of TransCanada's contracted supply by volume will have elected to participate in the Topgas Two Program.

With respect to the 10% of TransCanada's contracted supply under Topgas which is not included in Topgas Two, TransCanada has outstanding payments of $44.8 approximately $46.5 million in satisfaction of its 1982/83 take or pay obligation under the associated contracts. As these contracts retain the 60% obligation level, further take or pay volumes could be incurred in the 1983/84 and 1984/85 contract years. As at the date herein, TransCanada has outstanding direct take or pay payments totalling approximately $51.3 million (which includes the outstanding take or pay under Category E contracts).

III. History of Take or Pay Financing

During the 1976/77 contract year, TransCanada became obligated to make take or pay payments in the amount of $7.6 million. At that time, TransCanada viewed take or pay gas as a short-term phenomenon, properly viewed as inventory, and recoverable in the near future. Because of the anticipated short recovery term of this relatively small amount, TransCanada was able to obtain debt financing at prime.

During the 1977/78 contract year, TransCanada incurred take or pay to the extent of $150 million. These payments were also debt financed. TransCanada still viewed this prepaid gas as short term inventory, recoverable over a period of 1 - 3 years. During the 1978/79 contract year, TransCanada incurred further take or pay to the extent of $216 million. It became apparent that these take or pay payments would be outstanding for a longer period of time than TransCanada had initially anticipated.

In the 1979/80 contract year, a further take or pay obligation of $480 million was incurred. TransCanada proposed and was allowed by the Commission to include in its financing a 20% equity component, represented by redeemable preferred shares, in order that the take or pay asset over the longer term could be supported. At this time TransCanada characterized gas as a medium-term inventory, recoverable over a 3 - 5 year term.

TransCanada incurred a take or pay obligation in the 1980/81 contract year to the extent of a further $187 million, an amount somewhat less than the previous contract years because the 1980 allocation agreement had reduced TransCanada's annual take or pay obligation by 20%. Nonetheless, at the end of 1981, TransCanada's total outstanding take or pay balance was approximately $1 billion. The Commission allowed TransCanada to finance approximately 30% of this total take or pay balance with preferred shares, with the result that the overall

carrying charge rate was 21.3%, which included a provision for income tax on the preferred shares.

At the end of 1981, it became apparent that much larger take or pay payments would be required in future years and that TransCanada would not be able to recover gas in respect of such payments for a significantly longer period than originally anticipated. For these reasons, any further financing of take or pay would necessarily include a permanent equity component, which would take the form of TransCanada common shares. The issue of such shares would have represented a substantially more expensive financing method than had been available previously.

The Topgas Program was proposed in May of 1982. Upon implementation in October of 1982, the Topgas Program almost entirely removed take or pay from TransCanada's balance sheet. TransCanada's 1981/82 take or pay obligation was satisfied by payments from Topgas rather than through TransCanada, and Topgas advanced additional monies in respect of TransCanada's unamended 1980/81 take or pay obligation. As the Topgas refinancing was comprised totally of debt, the cost to the producer (per mcf) was significantly lower than it could have been had TransCanada undertaken the financing itself, and lower than the cost of the financing that TransCanada had previously been able to obtain.

As with the Topgas Program, the Topgas Two Program, as described above, was proposed to producers in November of 1983 in order that

TransCanada's 1982/83 take or pay obligation under the Topgas Agreement could be financed without the high cost of equity, and in order that future take or pay liabilities could be minimized.

IV. Financing of TransCanada direct take or pay obligations TRANSCANADA PREPAID GAS

By entering into the Topgas Two Agreement, producers representing approximately 90% of TransCanada's contracted supply by volume consented to recovery of the 1982/83 take or pay gas concurrently with the recovery of the Topgas Prepaid Gas rather than subsequent to the recovery of Topgas Prepaid Gas as had been the case under the unamended Topgas Agreement. Additionally, these producers agreed that such recoveries would be deemed as part of actual deliveries at the allocation levels required under the Topgas programs. By agreeing to both of these provisions, these participating producers substantially reduced the risk and uncertainty surrounding the recovery of such gas. This reduced risk and uncertainty, together with the indemnities provided to Topgas Two by TransCanada, allowed approximately $307 million of prepayments to be debt financed by Topgas Two at a rate of Prime plus 7/8%. As of the date of this application and because of repayments by producers and negative adjustments, this amount has been reduced to $296.5 million.

By not entering into the Topgas Two Agreement, those producers representing approximately 10% of TransCanada's contracted supply by

volume, retained the requirement that 1982/83 take or pay and any subsequent take or pay advances may only be recovered after full recovery by Topgas of Topgas Prepaid Gas. TransCanada anticipates that recovery of TransCanada Prepaid Gas may not commence until November of 1994.

Such recovery can take place after that time only when TransCanada has taken delivery in a particular contract year of full obligation volumes. Both these factors give rise to uncertainty of recovery. Additionally, the financing of the prepaid asset must be maintained undiminished over a period of up to 10 years. Recovery is anticipated thereafter over an additional five year term.

CATEGORY E CONTRACTS

Producers in Category E contracts are not in the Topgas Program. As the Topgas Two Agreement amended the Topgas Agreement, it was not offered to these producers. Therefore, Category E contracts require that TransCanada take or pay for gas up to full contract levels. TransCanada has sought to operate these contracts at allocation levels in order that gas produced thereunder not occupy a disproportionate part of TransCanada's market. However, operation at allocation levels has also resulted in substantial take or pay payments which must be recovered by TransCanada within the recovery periods specified by the contracts (5-10 years) or under TransCanada's original allocation arrangements (10 years). In order to recover these payments,

TransCanada must operate these contracts in excess of the obligation level, with the result that producers thereunder will have the benefit of a larger share of the market at the expense of producers who have participated in the allocation program under the Topgas Agreements. TransCanada submits that it is equitable that volumes of gas under the Category E contracts attract financing costs at the same rate as volumes of gas under other contracts in respect of which TransCanada has made direct take or pay payments.

V. Proposed debt/equity financing

TransCanada has sought the direction of experts in the field of utility financing in order to determine an appropriate capital structure for the financing of the long term TransCanada Prepaid Gas asset and of the Category E take or pay asset. Included herewith as Exhibit "A" and Exhibit "B" respectively are analyses in the form of testimony prepared by Dr. Stephen F. Sherwin and Gordon S. Lackenbauer, reviewing the nature of the asset represented by TransCanada's outstanding take or pay and containing their recommendations of the capital structure which they consider appropriate under the circumstances. Dr. Sherwin and Mr. Lackenbauer recommend that the take or pay assets described herein be financed with a capital structure of 60% debt and 40% equity, with an appropriate allowance for income taxes. This results, according to Mr. Lackenbauer, in a total cost of such capital of approximately 18.88%. TransCanada adopts the analyses and reasoning of Dr. Sherwin and Mr. Lackenbauer as set out in Exhibits "A" and "B" hereto.

During the period before the implementation of the financing structure proposed herein, TransCanada intends to encourage the participation in the Topgas Two Program of all producers who have not yet executed Topgas Two Agreements. To the extent that such producers participate in a proposed third Closing, the volume of TransCanada Prepaid Gas outstanding will be reduced.

VI. Conclusion

TransCanada respectfully requests that the Commission determine that, on and from May 1, 1984 and until all TransCanada Prepaid Gas and all prepaid gas outstanding under Category E contracts is recovered by TransCanada, it shall be just and reasonable to include and there shall be included in TransCanada's Alberta cost of service (Categories B_1B_3, D_1B_3 and E) the cost of capital, as described in this application, in respect of the financing of take or pay payments made by TransCanada in respect of TransCanada Prepaid Gas incurred during the 1982/83 contract year and outstanding under Category E contracts at the end of the 1982/83 contract year.

Dated at the City of Calgary, in the Province of Alberta, this 29th day of February, 1984.

TRANSCANADA PIPELINES LIMITED

Per: ______________________

E.W.H. Mallabone
Manager, Legal

Communications related to this
Submission should be directed to:

Mr. E.W.H. Mallabone
Manager, Legal
TransCanada PipeLines Limited
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Calgary, Alberta
T2P 3V6

EXHIBIT "A"

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TransCanada Pipelines Limited

Testimony

of

Stephen F. Sherwin

Q. Please state your name, profession, and employment.

A. My name is Stephen F. Sherwin. I am an economist and Executive Vice President of Foster Associates, Inc., an economic consulting firm whose principal office is located at 1101 Seventeenth Street, Northwest, Washington, D.C. 20036. A summary of my qualifications appears in Appendix A.

Q. Before which Canadian Boards have you previously presented evidence?

A. I have presented evidence on the fair rate of return and capital structure before the Public Utility Boards of Alberta (for three subsidiaries of Canadian Utilities, Ltd.), British Columbia (for Pacific Northern Gas and West Kootenay Power & Light), Manitoba (for Greater Winnipeg Gas), and Quebec (Gaz Metropolitain and Gazifere Inc.); the Ontario Energy Board (for Consumers' Gas, Union Gas, and Tecumseh Gas Storage); the National Energy Board

(for Interprovincial Pipe Line, TransCanada PipeLines, Trans-Northern Pipe Line, Trans-Quebec and Maritimes, and Westcoast Transmission); and the Canadian Radio-Television and Telecommunications Commission (for Bell Canada).

Q. What is the purpose of your evidence?

A. In connection with its applications to the Alberta Petroleum Marketing Commission to recover through its Alberta cost of service the costs of financing its 1981/82 and 1982/83 take or pay obligations, TransCanada PipeLines Limited (TCPL) has asked me to express an opinion on (1) the appropriate capital structure for the financing of take-or-pay related prepayments of approximately $51.3 million made directly by TCPL to producers, and (2) the appropriate return on such prepayments.

Q. What are your conclusions?

A. I recommend a return of 13.38%, plus an appropriate allowance for income taxes, based on the following:

	Capital Structure	Cost Rates	Cost Component
Debt	60.0%	13.5%	8.10
Equity	40.0	13.2	5.28
TOTAL	100.0%		13.38%

The recommended capital structure is similar to that used by the National Energy Board for TCPL's utility operations. The debt

rate of 13.5% reflects the current rate at which TCPL can raise long-term debt; the equity rate of 13.2% represents the following weighted average cost:

Preferred stock	12.0%	@ 9.0%	=	1.08
Common Equity	28.0%	@ 15.0%	=	4.20
	40.0%			5.28

The preferred stock rate reflects the current market rate; the common stock proportion and cost rate conform to the NEB's decision of June 1983. The weighted common stock cost component should track future NEB decisions.

The above recommendations are made in full awareness that the bulk of the take-or-pay prepayments -- made by Topgas Holdings Limited ("TOPGAS") and Topgas Two Inc. ("Topgas Two") -- are presently treated in the Alberta cost of service as being entirely debt financed, and that the TCPL's prepayments made in earlier years were treated as being financed only by debt and by debt and preferred stock.

My grounds for recommending a balanced capital structure with a 60/40 debt/equity ratio are essentially that TCPL's prepayments represent non-income-producing assets for which the recovery probably will not commence for 10 years. No utility can finance assets without equity, and no utility should finance additional assets without a commensurate equity component. The long-term nature of TCPL's prepayments entails inherent uncertainties,

which require a substantial equity cushion to avoid an adverse impact on TCPL's ability to finance other assets.

Q. Please summarize your understanding of the prepayments made under TCPL's take-or-pay provisions.

A. The $51.3 million prepayment represents approximately $6.5 million outstanding under Category E contracts at the end of 1983, and $44.8 million relating to the 1982/83 contract year (Categories B_1B_3 and D_1B_3). A synopsis of the origins of these payments may help to focus on the salient issues.

As a result of a substantial supply-demand imbalance in gas markets during the last six years, TCPL began making annual payments on take-or-pay obligations in 1977. By 1982, these payments aggregated $1.0 billion. In the early years, the payments were treated as debt financed, essentially because a rapid make-up was expected. In later years, as the sums escalated, the payments were financed by debt and preferred stock.

The prospect of further escalating payments prompted TCPL to negotiate an initial reduction in minimum annual gas takes for the 1980/81 and 1981/82 contract years from 100% to 80%, and to offer a further reduction in the take-or-pay floor to the lesser of 60% of TCPL's original minimum annual obligation for the 1981/82 contract year, or 75% of TCPL's minimum annual take obligation for a particular contract year. Under this plan,

recovery of the prepaid gas commences in the 1984/85 contract year, and extends over 10 years, subject to acceleration if market demand increases.

A major feature of this plan was the creation of Topgas Holdings Limited -- controlled by a consortium of Canadian banks -- to assume all of TCPL's prepayment obligations incurred through to the end of the 1981/82 contract year, amounting to $2.3 billion. Of this sum, TCPL was reimbursed for $1.0 billion paid in earlier years, and an additional payment of $1.3 billion was made directly to producers which represented payment for gas not taken during the 1981/82 contract year up to the 100% obligation level as well as payment for the 20% of the 1980/81 obligation initially waived by producers. The initial Topgas arrangement provided for an equity backstop by TCPL, in the form of (1) a $300 million principal guarantee and (2) a reimbursement guarantee to the bank of all carrying costs.

Virtually all the producers (99.9%) accepted the Topgas proposal. Under five contracts, which were not included in Topgas, $6.5 million was paid out by TransCanada at the end of 1982.

During the 1982/83 contract year, TCPL's takes of gas declined further to approximately 48% of minimum annual contract volumes, resulting in additional take-or-pay obligations. This prompted TCPL to propose Topgas Two, providing for payments for gas not

taken during that contract year and a further reduction in further contract years of the take-or-pay obligations from 60% to 50% of the 1981/82 annual contract volumes, with the proviso that in future years the minimum level would move between 50% and 60%, depending on levels of take in the immediately preceding two years. The make-up period for Topgas Two is the same as for Topgas.

Approximately (90%) of the producers accepted the Topgas Two proposal and received $307 million. TCPL provided an additional equity backstop guarantee amounting to $55 million, and again incurred reimbursement obligations for carrying costs. TransCanada paid approximately $48.8 million to producers under contracts which were not included in Topgas Two. The earliest possible date for the commencement of make-ups is 1990; the expected make-up period is 1994-98.

From a financial-risk point of view, several aspects should be noted.

1. While the Topgas arrangements alleviated a potential financial squeeze on TCPL, they did not free the company of a residual obligation. Thus, TCPL's equity bears the ultimate risk of the Topgas and Topgas Two principal payments up to $355 million. While this represents only 13% of the total Topgas and Topgas Two debt, the amount stays constant over the entire make-up period. Thus, as the make-up volume

reduces the banks' exposure, TCPL's equity backstop becomes a rising proportion of debt financing undertaken by the banks.

2. The time period for the "make-up" is longer for the Category B_1B_3 and D_1B_3 contracts ($44.8 million) than for the Category E contracts ($6.5 million); both are longer than the make-up period envisioned under the earlier prepayments. The longer the make-up period, the greater becomes the necessity for a balanced capital structure.

3. Additional direct payments by TCPL under contracts not included in Topgas Two may be incurred during the 1983/84 and 1984/85 contract years because of the higher obligation level in those contracts.

Q. What do you view as the principles governing the choice of an appropriate capital structure for these prepayments?

A. The guiding principle is found in the concept of an "efficient" capital structure, designed to minimize the total cost of capital. This concept is translated into practice by maintaining a balanced debt/equity ratio, consistent with the business risks of the assets.

Regulation proceeds generally on the premise that a utility's existing capital structure reflects (1) the exercise of prudent

managerial evaluation of the business risks, (2) the degree of risks the owners wish to assume, and (3) the exigencies of capital market conditions at the time the assets were financed. For these reasons, one finds considerable variations in existing capital structures of utilities with similar business risks. The differences in capital structure ratios then become an indication of the degree of financial risks the owners have assumed which, in turn, become a determinant of the level of compensation to which they are entitled.

Despite differences in existing capital structures among utilities of reasonably similar business risks, the utilities' existing actual capital structure have generally been accepted as a proxy for a reasonably efficient capital structure. The two principal exceptions are (1) truly uneconomic capital structures, e.g., equity ratios above 80% and (2) significant differences in the asset risks, e.g., utility operations and hydrocarbon exploration conducted under one corporate roof. Both exceptions lead the regulator to adopt "deemed" capital structures.

Because TCPL is a diversified utility-energy company, the National Energy Board determines TCPL's return on its pipeline operations by reference to a "deemed" capital structure, which represents a portion of the actual capital structure of TCPL's combined operations. The adoption of a capital structure for TCPL's Alberta cost of service constitutes merely another segmentation of its actual capital structure.

Irrespective of whether regulation proceeds on the basis of an actual or a deemed capital structure, the guiding criteria for a balanced capital structure are:

1. It should be consistent with the business risks of the assets.

2. It should permit financing on a stand-alone basis without giving or receiving subsidies from other assets of the business.

3. It should provide sufficient financial flexibility to avoid an adverse impact on the ability to finance additional assets.

Q. How do you propose to implement these principles for the financing of TCPL's direct gas prepayments?

A. The initial inquiry concerns the risks of the assets acquired by the prepayments. Economists frequently distinguish between risk and uncertainty. Risk is defined as the probability of failing to achieve the anticipated return or suffering an impairment of capital; uncertainty is a term reserved for the immeasurable aspects of unpredictable events. For the traditional utility's assets, return regulation evolves around the concept of risk; TCPL's prepayments fall into the realm of uncertainty.

The measurement of utility risks (for which there is no formula) typically relates to income-producing assets, for which the income received includes recovery of the invested capital over the life of the assets. The prepayments are not an income-producing asset, nor are they a futures contract entitling TCPL to purchase gas at today's price. They are merely a down payment for the right to purchase gas (at market prices) in the future. The risks of non-income producing assets are greater than for income-producing assets.

The evaluation of utility risks typically proceeds on the basis of experienced risks. There is no experience with the recovery of prepayments. One may speculate whether the reservoir conditions ten years hence may preclude some producers from delivering gas, whether the price of gas may render production of gas uneconomic, whether the regulatory mode may change over time so that some of the carrying costs may fall on TCPL, or whether, in the event of forfeiture, TCPL would be allowed to amortize any losses in its cost of service. Each of these aspects involves uncertainty.

The only certainty is that the \$44.8 million prepayments of B_1B_3, and D_1B_3 contracts are exposed to significantly greater risks than the \$6.5 million for Category E contracts. The recovery of the former is expected 10-15 years hence, compared to 5-10 years for the latter; none of the recovery of the \$44.8 million may even commence until the make-up of all the Topgas and Topgas Two contracts has been completed.

The fact that no portion of the $44.8 million prepayments will be recovered before the make-up period begins, and that the assets are not income producing, leads me to the conclusion that the risks lie above those of TCPL's pipeline assets. Giving consideration to the somewhat lesser risk of the $6.5 million prepayments for the Category E contracts leads me to the further conclusion that the combined risks of the $51.3 million prepayments are similar to those of TCPL's pipeline assets.

To place that conclusion in perspective, both the $44.8 and the $6.5 million payments arose out of market risks connected with pipeline operations; TCPL's risks for the prepayments can only be removed when the end-market absorbs the gas. Until such time, the risks of the prepayments are similar to the pipeline's overall risks.

I now turn to the "stand-alone" financing criterion. Lenders always require, even for the purchase of Government securities, some equity. The greater the risks and the longer the period of capital recovery, the greater becomes the required proportion of equity. A non-income-producing asset requires more equity than an income-producing-asset, because lenders like to see a positive cash flow to amortize the debt. The "stand-alone" principle may be translated into practice by examining the financing practices of other enterprises. The average debt/equity ratio for major Canadian Utilities -- approved by regulatory boards -- is approximately 52/48%; only one company significantly exceeds the 60/40 standard here proposed for TCPL's prepayments.

The third criterion relates to maintaining financing flexibility. If TCPL's prepayments were to be totally debt financed, it would adversely impact on its future ability to finance pipeline assets, for the reason that it provides no interest coverage, and could therefore adversely affect its credit rating. In essence, this criterion is a corollary to the principle that all financings should be consistent with relative risks. These risks of the prepayments are now greater than in earlier years (1977-81) when part of TCPL's take-or-pay obligations were financed by debt and by debt and preferred stock. The evolution of TCPL's financing of these prepayments should be viewed as similar to the utilities' evolution of construction expenditures costed at interest (IDC) in earlier years, compared to an allowance for funds, including a return on equity (AFUDC) in more recent times.

The above considerations lead me to the conclusion that the appropriate capital structure for TCPL's gas prepayments should closely track the 60/40 debt/equity ratio approved by the National Energy Board for TCPL's pipeline rate base.

Q. What cost rates do you recommend for the debt/equity ratio of 60/40 percent?

A. The impact of prepayments should not burden TCPL's distribution customers, or the ultimate consumers of gas. To avoid such a burdening, the prepayments should be viewed as identifiable assets, separately financed, at the <u>incremental</u> cost of capital.

Thus, the 60.0% debt portion should be costed at either the prime rate (on a floating basis) or, if financed by longer-term debt, at the effective rate (including financing costs) at which the designated issue is sold. The current long-term rate for TCPL's debt is 13.5%, including flotation costs.

The 40.0 percent equity component should be viewed as presently comprising 28.0 percent common equity (or the percentage approved by the National Energy Board in TCPL's pending application) and 12.0% preferred stock.

A 12.0 percent preferred stock ratio for a total capital of $51.3 million amounts to $6.1 million. That sum is too small to warrant issuing new preferred stock, because the flotation costs (legal and underwriting) would unduly raise the effective cost. Nevertheless, pending such an issue, producers should be entitled to the deemed lower cost of preferred (compared to common equity). The current rate for new preferred stock is approximately 9.0 percent.

In contrast to the specific designation of debt and preferred issues, common equity cannot be traced. Nevertheless, new equity issues, reploughed earnings or reinvestment of dividends constitute incremental common equity capital. As long as TCPL operates profitably, there will be sufficient new common equity to permit an attribution of a part thereof to TCPL's prepayments. The cost of such equity is a matter of informed judgment, constrained by

factual evidence with respect to alternative returns to investors. In my opinion, the equity return component for the prepayments should track the equity return allowance of the NEB, currently at 15.0% for TCPL's pipeline operations.

Since the equity return allowance constitutes an after-tax return to the investor, each dollar of equity return generates an income tax liability. It is therefore necessary to permit TCPL, as part of its cost of service, the recovery of income taxes on the equity component, computed at the marginal tax rate.

Q. Do you have an opinion on the propriety of the 11 7/8% rate used by TCPL on an interim basis?

A. I view that rate as an accommodation pending a regulatory determination of an appropriate capital structure and specific rates for the different components of the capital structure. An 11 7/8% rate, without any allowance for income taxes, lies only marginally above the prime rate and this falls short of TCPL's cost of capital.

Q. Does this conclude your testimony?

A. Yes.

APPENDIX A

Summary of Qualifications

of

Stephen F. Sherwin

I hold the degrees of Bachelor of Business Administration (1949), Master of Business Administration (1951), and PhD. in Economics (1956), all from the University of Wisconsin. My fields of study were Accounting, Economics, Finance, and Public Utilities.

After completing my graduate studies, I was an instructor in Economics at New York University. I have also been a guest lecturer at Penn State University and The George Washington University.

In 1956 I joined Foster Associates, Inc. During the last twenty-seven years I have been a consultant to both industry and government. In the course of these consulting activities, I have made numerous studies on the cost of capital and reasonable earnings requirements for airlines, electric and gas distribution utilities, natural gas pipelines, telephone companies, and water companies. I have also made studies of the economics and cost characteristics of the oil and gas industry, on selected aspects of taxation, on postal economics, and the securities industry.

The results of many of those studies have been presented as testimony before regulatory agencies in over eighty proceedings in the United States and Canada.

In Canada, I have submitted rate of return evidence during the last nine years in more than thirty proceedings before the National Energy Board (TransCanada PipeLines, Trans-Northern Pipe Line Co., Westcoast Transmission and Interprovincial Pipe Line Limited), the British Columbia Energy Commission (Pacific Northern Gas and West Kootenay Power & Light), the Ontario Energy Board (Consumers' Gas and Union Gas), the Public Utility Boards of Alberta (Alberta Power, Canadian Western Natural Gas, and Northwestern Utilities), Manitoba (Greater Winnipeg Gas); the Regie de L'Electricite et du Gaz of Quebec (Gazifere Inc. and Gaz Metropolitain); and the Canadian Radio-Television and Telecommunications Commission (Bell Canada).

In the United States, I submitted rate of return evidence before the Civil Aeronautics Board (Braniff, Continental, National, and Western Airlines); the Federal Energy Regulatory Commission (South Carolina Electric & Gas, Great Lakes Gas Transmission, Duke Power, Southern Union Gathering, Interstate Storage Division (Michigan Consolidated Gas), and Western Gas Interstate); the Public Service Commissions of Arizona (Southern Union Gas), the District of Columbia (Chesapeake & Potomac Telephone Company), Florida (Tampa Electric and General Telephone of Florida), Hawaii (Hawaiian Telephone), Maryland (Baltimore Gas & Electric), Michigan (Michigan Consolidated Gas), Missouri (Laclede Gas), New Mexico (Gas Company of New Mexico), New York (St. Lawrence Gas), North Carolina (Duke Power), Ohio (Dayton Power & Light), South Carolina (South Carolina Electric & Gas and Duke Power), Texas (Houston Lighting & Power), Virginia and West Virginia (Chesapeake & Potomac Telephone Companies, AT&T subsidiaries); before the Securities and Exchange Commission (for the National Association of Securities Dealers) on the subject of reasonable sales charges for mutual funds;

before the Interstate Commerce Commission and the Postal Rate Commission (for the U.S. Postal Service and two mailers' trade associations) on the costing and pricing of postal services; and before the Federal Power Commission (for Exxon, Gulf, Mobil, Texaco, and other oil companies) in twelve proceedings (including the Permian Basin and Area Rate Proceedings) concerned with the costing and pricing of natural gas at points of production.

<u>Publications</u>

"Monetary Policy in Continental Western Europe (1946-1951)", University of Wisconsin Press (1956).

"Cost of Natural Gas", <u>Journal of Petroleum Technology</u> (February 1965).

"Report on Principles of Costing and Rate Making for the U.S. Postal Service", co-author with H. Herz, <u>President's Commission on U.S. Postal Organization</u> (1968).

"Cost of Finding Hydrocarbons", Bureau of Land Management, Technical Bulletin 5 (May 1970).

"Economic Criteria for Postal Rate Making", <u>Washington and Lee University</u> (March 1977).

"The Rationale and Application of the Comparable Earnings Method", <u>Earnings Regulation Under Inflation</u>, Institute for Study of Regulation (1982).

EXHIBIT "B"

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TRANSCANADA PIPELINES LIMITED

Testimony of

<u>Gordon S. Lackenbauer</u>

Q. Please state your name, address and occupation.

A. My name is Gordon Stanley Lackenbauer. My business address is P.O. Box 35, Toronto-Dominion Centre, Toronto, Ontario, M5K 1C4. I am a Senior Vice President and Director of Nesbitt Thomson Bongard Inc., an investment dealer with offices in the principal cities of Canada and subsidiary companies in New York, London and Zurich. Nesbitt Thomson is a major underwriter and distributor of corporate and government securities and has extensive experience in the utility sector. My education and business experience are set out in Appendix A.

Q. What is the purpose of your testimony?

A. TransCanada has requested me to express an opinion on the appropriate method and related cost of financing its direct prepayments of approximately $51.3 million to producers pursuant to its take or pay obligations outside of the Topgas agreements. I have been informed that these prepayments could approximate $150 million, based on a 60% obligation level and on the 1982/83 unit price.

Q. What are your conclusions?

A. In my opinion, the most reasonable and practical approach would be to finance the direct prepayments using the same capital structure as that determined by the NEB for TransCanada's jurisdictional utility operations. However, the costs of the various capital components should be the marginal cost of the new capital required to finance such prepayments to ensure that the Alberta cost of service determination incorporates the full cost of the direct prepayments to the related producers who have chosen to remain outside the Topgas agreement. For purposes of the determination of such costs, the allowed rate of return on common equity determined by the NEB should be adopted, together with the actual costs of debt and preferred share capital to be raised. To illustrate, TransCanada's approved capital structure, excluding deferred taxes, for the current test year is approximately as follows:

Long-term Debt	60.0%
Preferred Share Equity	12.0
Common Equity	28.0
	100.0

The current costs of raising $51.3 million in such form under prevailing market conditions would approximate 13.38% based on the allowed rate of return on common equity of 15%, the 13 1/2% all-in annual cost of raising 15-year fixed rate debt with an

offering yield to maturity of approximately 13.25% and the 9% annual cost of raising 10-year retractable preferred shares. After provision for appropriate income taxes, the total cost of such capital would approximate 18.88%. Of course, the actual costs may differ somewhat from the above illustration depending upon the actual costs of such capital and any changes in TransCanada's capital structure and allowed rate of return subsequently approved by the NEB.

Q. Why have you reached such a conclusion?

A. My conclusions were determined in light of the risks associated with prepayments outside of the Topgas agreements and my assessment of the ability to finance such payments on a stand-alone basis. It is my understanding that most of the gas related to such direct prepayments can be recovered only after gas related to the Topgas agreements has been recovered. The Topgas structure provides for recovery over the 10-year period ended November 1, 1994, although it is conceivable that such recovery could be completed within approximately eight years. Accordingly, the recovery of gas for which prepayments have been made outside of Topgas can only be anticipated over a 10 to 15-year period unless Topgas is completed earlier, subject to certain exceptions and conditions.

In my opinion, the direct prepayments on a stand-alone basis could not be financed with more than 60% debt for a term of up to

15 years. More realistically, it would be quite unlikely that more than 50% debt could be raised on such credits. Nevertheless, in view of the relative magnitude of the amounts involved actually and potentially, I do not think it is necessary to debate the notional differences between the likelihood of achieving 50% or 60% debt ratios. Rather, I believe the adoption of the utility company capital structure is a reasonable compromise as a proxy for an acceptable stand-alone financing approach that does not undermine the principles at issue here.

Q. From a financial viewpoint, what is the basic principle at issue here?

A. Conceptually, it appears to me that the basic financial principle at issue here is the appropriate method of financing long-term assets. An absolutely fundamental premise of financial theory and practice is that the apparent source of cash used to acquire a particular asset cannot be used to justify that investment decision. Stated differently, dollar-tracing is an irrelevant exercise. The roads to the bankruptcy arena and failed courses in introductory finance are littered with the proponents of such an approach.

A firm has access to short-term funds based on its general credit standing which in turn reflects the appropriateness of its corporate capital structure both on an actual and a prospective basis. A firm with no equity cannot raise debt in any form to

finance its investments. In essence, this information response arises from the argument that a firm can raise debt without any equity. Such an argument can be nothing more than one of convenience which chooses to ignore TransCanada's equity capital that is underpinning both its short-term and long-term debt and focuses on an attempt to "colour code" dollars back to the cheapest source available. I am confident that if the tracing process happened to indicate that the actual cash was provided by a common equity issue, there would be no argument that TransCanada's cost of funds for such prepayments was approximately 15% before provision for income taxes and, accordingly, approximately 30.6% on a pre-tax basis.

In real terms, the Topgas agreements clearly serve to illustrate this point. Under this approach, the banks have required TransCanada effectively to "backstop" $355 million of the $2.6 billion while, commencing November 1, 1984, the loan reduces annually to the extent of 10% of the prepaid gas originally outstanding under the Topgas programs. In fact, the Topgas Two agreement provides for a backstopping of $55 million against a loan of $296 million, which represents an initial equity cushion of almost 20%. There is no schedule providing for the reduction of TransCanada's $355 million undertaking and the banks' equity protection, therefore, is growing steadily through the term of the agreement. In addition, TransCanada had to agree to pay any of the Topgas interest costs not recoverable through the Alberta

cost of service. It must be recognized that the Topgas agreements fully reflect arm's length negotiations of financing prepayments on a stand-alone basis and that the risks associated with failing to recover the gas related to such prepayments are less than those associated with TransCanada's direct prepayments which include a much longer term of recovery, no expected cash flow for the first 10 years and a group of companies with a lower level of creditworthiness than those involved in Topgas Two. The favourable interest rate of prime plus 7/8 of 1% on the Topgas financing reflects the term to maturity of approximately 11 years and an average term of approximately six years, the relatively low risk associated with the recovery of the gas related to the Topgas prepayments and the increasing relative equity cushion provided by TransCanada over the 11-year period.

Q. What are the implications for TransCanada's financing flexibility if it was able to obtain only a debt rate of return on its direct prepayments to producers?

A. Clearly, such treatment would have a negative impact on TransCanada's financing flexibility and could result in an erosion of its creditworthiness. That was exactly the reason why the Topgas arrangements were structured in the first place. Such treatment is simply a form of cross subsidization which is a subject matter of considerable ongoing concern to regulators in general.

The basic principle, as outlined earlier, comes down to the appropriateness of a corporation's capital structure in the financing of all of its assets. Notionally, all long-term assets are financed by the overall long-term capital structure. Short-term borrowings are viewed as either financing short-term assets or as interim financing of long-term assets which ultimately will be funded by long-term capital on the basis of the corporation's ongoing long-term capital structure. Accordingly, TransCanada's direct prepayments to producers should be funded by a capital structure with no less equity than that approved for its jurisdictional utility operations by the NEB since, at a minimum, the risks associated with recovering the gas related to the direct prepayments on a stand-alone basis are no less than those associated with TransCanada's transmission operations in Canada.

Q. Does this approach provide the lowest cost that is available to TransCanada to finance its direct prepayment obligations for a term of up to 15 years?

A. Yes. The very nature of an optimal or efficient capital structure ensures that the pre-tax cost of capital to a firm is minimized within the context of maintaining an appropriate level of financing flexibility to meet future growth. This consideration is of paramount importance to regulatory boards everywhere and is a critically important factor in the process of the evaluation and approval of a utility company's capital structure and cost of capital.

Q. At the beginning of your testimony, you set out the ratios for TransCanada's capital structure which implies various minimum issue sizes for debt, preferred share and common equity capital. Will TransCanada actually raise such relatively small amounts of funds in the capital markets?

A. Yes, except in the case of preferred shares. TransCanada's dividend reinvestment plan (DRIP) will provide a minimum amount of $50 million of new common equity in 1984, with the initial injection of such equity occurring in January. The expected proceeds from its DRIP are in the range of $52 million to $60 million, of which $14.4 million is required to fund the common equity portion of the $51.3 million of direct prepayments. Of course, TransCanada's increase in retained earnings through reinvestment of a significant portion of its 1984 net income also represents new equity to the company that would be available to fund its prepayment requirements.

The debt portion of the $51.3 million will require a debt issue with net proceeds of approximately $30.8 million. It would be a simple matter to raise this money in the private placement market in Canada since the issue size does not warrant going to the public market. However, it is also conceivable that the company may wish to raise debt with the same maturity for its other jurisdictional or non-jurisdictional operations, in which case it would do a larger issue in the public markets and allocate $30.8 million of the net proceeds to the funding of its $51.3 million requirements.

The balance of \$6.1 million should be funded by preferred shares. However, such a small issue for a company of the size and stature of TransCanada would be both unusual and administratively costly. Since the company has no expectation that it will raise any preferred share capital for other purposes in 1984, it would not expect to do an issue for only \$6.1 million. However, because TransCanada is choosing not to raise such funds, it should not expect to charge a higher cost than would be associated with such an issue. Accordingly, TransCanada will fund the \$6.1 million in 1984 with additional common equity pending any increase in its prepayment obligations and/or its other corporate needs which would necessitate any need for additional preferred share capital in 1985 or beyond. During this period, it would only seek a preferred share rate of return on the \$6.1 million of its common equity that actually would be funding the notional preferred share component of its \$51.3 million requirement. Beyond 1984, TransCanada very well may raise preferred share capital and would allocate the appropriate amount to its direct prepayment obligations at that time. In the meantime, a 10-year retractable preferred share issue of TransCanada for its current needs would require an offering yield of approximately 9% under current market conditions.

Q. What is the appropriate tax treatment to use in this situation?

A. On a stand-alone basis, one must adopt the marginal costs associated with the financing of the assets involved to ensure no

cross-subsidization. Since the particular assets in this situation are prepayments for future gas deliveries, it follows that there are no capital cost allowances available to shield any of the taxes related to collecting the after-tax cost of the preferred share and common share equity capital that is funding approximately 40% of these prepayments. Accordingly, the marginal tax rate of approximately 51% will apply in full to both components of equity capital.

Q. What is an appropriate interim cost rate for the $51.3 million?

A. Once one departs from adopting the weighted cost of capital, including a provision for related income taxes, based on the capital structure financing a company's long-term assets, there is no conceptually correct basis for determining an appropriate interim rate. Regulatory boards in North America have recognized this principle for a long time and have been guided accordingly as evidenced by the widespread use of the weighted cost of capital as the AFUDC rate for construction work in progress, even though such construction is often apparently partly financed on an interim basis with cash raised from various short-term money market sources.

TransCanada was able to negotiate the Topgas loan agreements with a banking syndicate to finance its take or pay obligations on terms that are very attractive to the producers and that are "off balance sheet" to TransCanada. The rate of prime plus 7/8% of 1%

was particularly attractive for a loan of such duration and the high effective amount of leverage inherent in that financing. While producers accounting for approximately 20% of the take or pay volumes did not execute the Topgas Two agreement in time to participate in the first Closing, TransCanada decided that until the final outcome of discussions with the non-participating producers was determined, it would charge such producers only that amount applicable under Topgas Two simply as an accommodation on an interim basis.

Clearly, TransCanada's costs of capital to finance the $51.3 million for a term of up to 15 years are far greater than prime plus 7/8 of 1% for the reasons outlined earlier. Further, the risks associated with such prepayments are higher than those associated with the Topgas Two agreement. The interim rate of prime plus 7/8 of 1% on the $51.3 million of direct prepayments is a very favourable rate indeed. This rate should be replaced by TransCanada's weighted marginal cost of capital as soon as these costs are incurred or deemed to be incurred.

Q. Does this conclude your testimony at this time?

A. Yes.

APPENDIX A

GORDON S. LACKENBAUER

Education and Business Experience

I graduated from Loyola College with a B.A. - Honours Economics in 1965 and from the University of Western Ontario with a M.B.A. in 1968. In 1976, I obtained the designation of Chartered Financial Analyst. I joined the firm of Nesbitt Thomson and Company Limited, a national investment dealer, in June 1968 and was employed with that firm until January 1977, at which time I joined Pitfield Mackay Ross Limited as a Vice President and Director in the Corporate Finance Department. In November 1982, I returned to Nesbitt Thomson Bongard Inc. as a Senior Vice President and Director in the Corporate and Government Finance Department.

Since early 1969, I have been primarily involved with the underwriting and distribution of corporate debt and equity securities, although from October of 1980 until July of 1981 I spent a considerable amount of time on a special assignment as a representative of the Federal Government to assist Massey-Ferguson Limited and other interested parties and investors to put together an adequate recapitalization plan for the company. Since 1975, I have also appeared as an expert financial witness in various proceedings before the National Energy Board, the Ontario Energy Board and the Public Utilities Board of Alberta as well as in a private arbitration proceeding in Alberta.

TransCanada PipeLines
TRANSCANADA PIPELINES TOWER, 530 EIGHTH AVENUE S.W.
P.O. BOX 500 STATION M, CALGARY, CANADA T2P 3V6
(403) 269-5611

April 24, 1984

Alberta Petroleum Marketing Commission
#1900 Bow Valley Square IV
250 - 6th Avenue S.W.
Calgary, Alberta
T2P 3H7

Attention: Mr. V. Thomas

Dear Sir:

Regarding the request of the Commission in its letter of April 16, 1984 relating to TransCanada's application dated February 29, 1984 (Docket No. 84-15) for financing TransCanada Prepaid Gas, submitted herewith is the information and clarification requested.

Q. 1. Please explain the distinguishing features that cause the recovery period to vary among gas purchase contracts in Category E.

A. The five gas purchase contracts which are included in Category E of TransCanada's Alberta cost of service have varying contractual provisions for prepaid gas recovery. The incurrment of take or pay under the particular contracts is shown on the attached schedule.

Gas Contracts #01120 and #01379 are reserve type contracts which provide for a 5 year recovery period. Gas Contract #01388 is a reserve type contract which provides for a 10 year recovery period. Gas Contracts #01100 and #01624 are stipulated number of days contracts which have no provision for payments for prepaid gas or right of make up.

All five contracts were included in the 1978, the 1979 and the 1980 allocation agreements. These allocation agreements provided for the making of take or pay payments for gas not taken and provided for a right of make up of the prepaid gas. TransCanada has the right to recover prepaid gas incurred under any contract in the contract years 1976/77 through 1981/82 inclusive during the 10 contract years next succeeding the contract year in which the prepaid gas was incurred. Prepaid gas may only be recovered during a contract year after TransCanada has complied with the minimum take or pay for obligation during the particular contract year, and any such further delivery of gas shall be

.../2

deemed to be recovery in equal proportions of the "Additional Volumes" and of Prepaid Gas.

TransCanada has the right under the gas purchase contract unamended by the allocation agreements to recover prepaid gas incurred in the 1982/83 contract year during the recovery period set out in the particular contract after complying with the minimum take or pay for obligation during that particular contract year.

Q. 2. Please provide the most current projection together with the maximum time allowed for recovery under the gas purchase contracts in Category E.

A. Attached is a schedule of "Category E Take or Pay Recovery Estimates".

Yours very truly

E.W.H.Mallabone
Manager, Legal
EWHM:ed
Encls.

CATEGORY E CONTRACTS

CONTRACT NO.	YEAR	$ O/S
00110	77/78	$ 103,660.53
	78/79	47,253.27
	79/80	491,373.36
	80/81	
	81/82	822,512.78
	82/83	
	TOTAL	$1,464,799.94
01624	77/78	$ 12,155.05
	78/79	5,244.56
	79/80	11,369.88
	80/81	5,493.24
	81/82	10,251.76
	82/83	
	TOTAL	$ 44,514.49
01120	77/78	$ 213,643.49
	78/79	379,425.80
	79/80	1,016,586.19
	80/81	562,137.59
	81/82	444,590.54
	82/83	
	TOTAL	$2,616,383.61
01379	77/78	$ 2,888.82
	78/79	1,527.01
	79/80	4,884.00
	80/81	2,620.94
	81/82	5,327.03
	82/83	15,761.33
	TOTAL	$ 33,009.13
01388	77/78	$ 345,432.49
	78/79	366,725.76
	79/80	918,182.02
	80/81	286,162.74
	81/82	413,042.40
	82/83	1,518,714.35
	TOTAL	$3,848,259.76

CATEGORY "E": TAKE-OR-PAY ESTIMATE

Contract	Dispatch Group No.	Take-or-Pay $10^3 m^3$	Take-or-Pay $	Estimate of Recovery	Recovery Completed By End of: (If Started in 84/85)
01100	1154-01 1220-02	17,460.9(+34,674.1 additional)	$1,010,453.80	8 years	1991/92
01624	1201-03	855.8(+533.5 additional)	$ 44,514.49	8 years	1991/92
01120	1146-01	47,673.4(+19,169.8 additional)	$2,616,383.61	8 years	1991/92
	1427-03	18,328(+7,546.3 additional)		5 years	1988/89
01379	1168-52	510.8(+155.8 additional)	$ 33,009.13	9 years	1992/93
01388	1307-01	61,944.3(+17,782.8 additional)	$3,848.259.76	9 years	1992/93
		TOTAL	$7,552,620.79		

ASSUMPTIONS AND NOTES

1. Assumes recovery by higher-of: i.e., for deliverability contracts, # of days incurred = # of days recovered; for reserve based contracts, recovery = (contract max - contract min) X 365. Recovery flexibility must be considered because under deliverability contracts the number of days per year available can vary, and under reserve contracts the ratio of contract max to contract min can vary.

2. Recovery estimate ignores any "additional" volumes, i.e., not taken and not paid for, that may have been left after take-or-pay was recovered.

3. All contracts are assumed participants to 1980-08-27 allocation agreement, and recovery of prepaid and additional volumes was estimated per the terms of that amended agreement.

DETERMINATION 83-08 (TCP)
Alberta Cost of Service
Natural Gas Pricing Agreement Act

APPLICATION

By application dated August 8, 1983, TransCanada PipeLines Limited (TransCanada) requests that the Alberta Petroleum Marketing Commission (the Commission) modify the rate of return on rate base used in determining TransCanada's Alberta cost of service in accordance with the Decision of the National Energy Board dated June, 1983. TransCanada also requests a revision to the current procedure of making application for periodic changes in the rate of return on rate base. The application (except for attachments) is shown in the attached Appendix A.

DECISION

1. TransCanada's rate of return on rate base for Alberta cost of service shall be 14.00 percent effective August 1, 1983.

2. TransCanada's request for revision to the current procedure of making application for periodic changes in the rate of return is denied.

REASONS

The Commission has in the past taken into account decisions made by other regulatory bodies exercising jurisdiction over transmission companies operating both within and without the Province of Alberta when such decisions have been consistent with Alberta law and Commission policies relating to Alberta cost of service. The Commission has reviewed the National Energy Board's Reasons for Decision and considers a 14.00% rate of return on rate base to be appropriate for Alberta cost of service.

DATED THIS 6th day of October, 1983, at Calgary, Alberta.

R. D. Hall
Vice-Chairman

IN THE MATTER OF AN APPLICATION

by TransCanada PipeLines Limited

to the Alberta Petroleum Marketing Commission

to modify the rate of return on rate base

in TransCanada PipeLines Limited's

Alberta Cost of Service

August 1983

REQUEST

TransCanada PipeLines Limited (TransCanada) hereby applies to the Alberta Petroleum Marketing Commission (the Commission) for approval to modify the rate of return on rate base used in determining TransCanada's Alberta cost of service in accordance with the Decision of the National Energy Board (NEB) dated June, 1983. TransCanada also requests a revision to the current procedure of making application for periodic changes in the rate of return on rate base.

In its Decision, the NEB allowed TransCanada to earn a 14.00% rate of return on rate base based on a deemed capitalization. A 15.00% return on a deemed common equity of 28% is included as a cost component in the approved rate of return. A copy of the NEB Decision which includes Orders No's. RH-2-83, TG-4-83, TG-5-83, and AO-1-TG-3-82 and the Reasons for Decision are attached as Exhibit "D" hereto. The pertinent information in the Reasons for Decision referring to the rate of return, is included under Chapter 3, page 9 through to and including page 13.

PRESENT PRACTICE

The previous rate of return on rate base approved by the NEB, which has been employed in calculating TransCanada's Alberta cost of service, was 13.88%. This rate has been effective from September 1, 1982 to July 31, 1983.

The Commission, by Determination 82-11 (TCP) dated 1982-11-09 accepted and approved the rate of return as set by the NEB.

The previous and present capital structures of TransCanada, approved by the NEB, are shown in Appendix V of the Reasons for Decision.

REASONS FOR THE REQUEST

The principles and methods which have been applied in the determination of TransCanada's Alberta cost of service, other than NOVA, An Alberta Corporation charges, are consistent with those approved by the NEB in establishing TransCanada's transmission tariff.

In prior determinations, the Commission has taken into account decisions made by the NEB providing such decisions were consistent with requirements of the Natural Gas Pricing Agreement Act or Commission policies relating to Alberta cost of service.

If a component of TransCanada's cost of service were to be allocated by the NEB to the transmission tariff on a basis which is different from the basis of allocation used by the Commission, this inconsistency would result in TransCanada obtaining more or less than its reasonable and necessary costs.

It is submitted that TransCanada adduced substantial evidence of its particular needs and circumstances at a public hearing held before the NEB in the months of May and June 1983. The producers, who were fully

represented at this hearing, cross-examined TransCanada extensively and submitted their own rebuttal evidence. The NEB thus had before it the full evidence and representations of TransCanada, the producers and other intervenors concerning TransCanada's particular needs and circumstances and the interests of the producers and other intervenors. The NEB considered and weighed this evidence and these representations in reaching its conclusions.

In view of these facts, TransCanada requests that this NEB Decision be applied uniformly in order to avoid unnecessary duplication of the regulatory process and unwarranted gains or losses to TransCanada.

In reference to the procedural change, it is TransCanada's opinion that the proposed method will facilitate both the administrative and regulatory processes in that it would dispense with the necessity for future periodic applications to the Commission when the only change is that of rate of return on rate base. Since the Commission currently monitors the NEB decisions, and for the previously mentioned reasons of consistency, it is proposed that TransCanada need only supply the Commission with a copy of the NEB Reasons for Decisions. If the NEB's decision impacts TransCanada's Alberta Cost of Service in any other area, then TransCanada will make application accordingly.

ANTICIPATED EFFECT ON TRANSCANADA'S ALBERTA COST OF SERVICE

The higher rate of return approved by the NEB will result in an estimated increase to TransCanada's Alberta cost of service (return component Line 8 per "Exhibit "A") of approximately $88,548 during the twelve month period ending July 31, 1983. The detailed calculations and assumptions are shown in Exhibits "A", "B" and "C".

Dated at the City of Calgary, in the Province of Alberta this 5th day of August, 1983.

Respectfully submitted
TRANSCANADA PIPELINES LIMITED

By:
E.W.H. Mallabone
Manager, Legal

Communications related to this Application should be directed to:

Mr. E.W.H. Mallabone
Manager, Legal
TransCanada PipeLines Limited
P.O. Box 500
Calgary, Alberta
T2P 2M7

DETERMINATION 84-19 (ICG)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

APPLICATION

By application dated November 1, 1983 and amended by letter dated February 16, 1984, ICG Resources Ltd. (ICG) requests an Alberta cost of service to be structured as proposed in the application. The application is attached as Appendix "A".

DECISION

The application is granted with effect from November 1, 1983.

REASONS

The structure of the Alberta cost of service herein follows practices and principles applied to other original buyers in similar circumstances.

DATED THIS 8th day of June, 1984 at Calgary, Alberta.

M R Pullam

M. R. Pullam
Acting Secretary

0541F APPENDIX "A"

ICG RESOURCES LTD.

Application to the Alberta Petroleum Marketing Commission requesting approval to file and have determined an Alberta Cost of Service

November 1, 1983

Prepared on behalf of ICG Resources Ltd. by Pan-Alberta Resources Inc.

(Contact: J. Lawton, Supervisor, Accounting, 234-6615)

INDEX

ICG RESOURCES LTD.

Statement of Request

ICG Resources Ltd. ("ICG") has contracted for the purchase of natural gas from producers within the Province of Alberta for sale, of such gas, to Pan-Alberta Gas Ltd. ("Pan-Alberta"), at a point at or near Empress, Alberta. Such gas would then be removed from Alberta under Pan-Alberta's gas removal permits PA 80-3 and/or PA 81-4 for subsequent resale to Societe quebecoise d'initiatives petrolieres for subsequent resale to Gaz Inter-Cite Quebec Inc. for ultimate distribution within a predetermined territory of Quebec, Canada.

ICG requests approval from the Commission to file and have determined monthly, a cost of service attributable to the acquisition, movement, metering, processing and marketing of this natural gas within Alberta.

Also, given that ICG will be initially purchasing gas exclusively from one area, the potential exists for a month in which no or little gas is purchased. This could be the result of producer force majeure, plant turn-arounds, etc. This obviously will create a situation where ICG will be unable to recover its "determined" Alberta Cost of Service. It is therefore requested that ICG be allowed to defer the recovery of such costs and any associated carrying costs to the next month of gas purchases, at which time the costs would be rolled into that month's costs and recovered. The timing and magnitude of any such deferrals will determine the method of recovery best to employ and ICG will ensure sufficient lead time is available for the Commission and ICG to determine what is mutually acceptable.

The requested approvals should recognize a November 1, 1983 project commencement date.

Reason for Request:

The Natural Gas Pricing Agreement Act provides for the regulation of natural gas prices. The components that comprise the purchase price (regulated field price) for original buyers of gas "intended to be removed from Alberta" are:

The Alberta Border Price

Less:

The Alberta Cost of Service (determined by the Commission)

Plus:

The Border Price Adjustment

ICG has specific responsibilities as an orignal buyer, one of which is the requirement to apply monthly to the Commission for determination of an Alberta Cost of Service.

Anticipated Cost of Service Components:

With the Commission's approval the components of Cost of Service will include:

Schedule	Component
1)	ICG's in-house operating costs
2)	Pan-Alberta Gas Ltd. Alberta removal permit fees
3)	Pan-Alberta Resources Inc. consulting fees
4)	NOVA, AN ALBERTA CORPORATION transportation costs
5)	A return on rate base

The following schedules will indicate the projected ICG cost of service for 1984. Subsequent years should not vary significantly.

If ICG becomes aware of significant changes from that currently projected ICG will inform the Commission of such.

As a contracted shipper on the Nova facilities any allocated fuel usage or measurement variance gas would represent, to ICG, an in-Alberta sale to Nova at the regulated field price (excluding the Border Price Adjustment). As such, ICG will report an Alberta Sales Adjustment component in it's cost of service recognizing the unrecovered cost of service associated with this sale. At this point ICG has no means of determining the magnitude of this sale.

ICG RESOURCES LTD.

Projected Alberta Cost of Service
For the Year Ended December 31, 1984

Details	Schedule	$'s
In-House Operating Costs	1	6,000
Pan-Alberta Gas Ltd.		
Permit Fees	2	100,000
Pan-Alberta Resources Inc.		
Consulting Fees	3	115,000
NOVA, AN ALBERTA CORPORATION		
Transportation Costs	4	701,000
Return on Rate Base	5	--
Total		922,000
Projected Purchases (GJ)		2,500,000
Per Unit Cost of Service ($/GJ)		.36880

Schedule 1

ICG RESOURCES LTD.

In-House Operating Costs

The anticipated annual in-house operating costs are projected to be approximately $6,000.00. The methodology proposed to segregate costs between ICG's production activities and it's original buyer activities will involve allocation of office rental costs, office supply costs, allocated employee benefit costs and salary costs based on actual employee time charged to the project. Time so charged will be costed and its percentage of the total company salary cost will become the allocation percentage to be applied against these common cost elements. Also direct project costs will be allocated on an as incurred basis (telephone, employee expenses etc. ...).

Schedule 2

ICG RESOURCES LTD.

Alberta Removal Permit Fees

ICG entered into a Gas Purchase Agreement, dated 83.08.22 with Pan-Alberta Gas Ltd. ("Pan-Alberta") under which ICG will sell the available gas to Pan-Alberta at the Alberta Border Price for removal under it's Alberta removal permits PA 80-3 and/or PA 81-4 at a cost of 4¢ per gigajoule of gas removed (Annual permit usage fee to be adjusted annually by a factor equal to the percentage change in the Implicit Price Deflator for Gross National Expenditure, Published Quarterly in Statistics Canada Catalogue, 13-001, National Income and Expenditure Accounts, System of National Accounts).

Projection:

Assuming a 183.0 $10^3m^3/d$ flow the anticipated 1984 annual permit fees will be:

$$183.0\ 10^3m^3 \times 37.43\ MJ/m^3 \times 365$$
$$= 2,500,000\ GJ \times 4¢/GJ = \$100,000/year$$

Consulting Fees

ICG has entered into a Consultant Operator Agreement with Pan-Alberta Resources Inc. ("PARI") dated 1983 08 01, under which PARI will provide consulting, operating and administrative services in connection with coordinating the ordering, transportation and delivery of ICG's gas. This agreement calls for a monthly fee payable to be the greater of:

- \$8,000/month (minimum monthly charge)

  or

- 4.6¢ per gigajoule of gas removed from Alberta

(These fees are to be adjusted annually by a factor equal to the percentage change in the Implicit Price Deflator for Gross National Expenditure, Published Quarterly in Statistics Canada Catalogue, 13-001, <u>National Income and Expenditure Accounts, System of National Accounts</u>).

The annual fee will <u>not</u> exceed the greater of:

- the minimum monthly charge (as adjusted) X 12.

  or

- the per GJ fee (as adjusted) of gas removed from Alberta.

<u>Forecast:</u>

Assuming a 183.0 $10^3m^3/d$ flow the anticipated 1984 annual consulting fees will be:

$183.0\ 10^3m^3 \times 37.43\ MJ/m^3 \times 365$

$= 2,500,000\ GJ \times 4.6¢/GJ = \$115,000/year$

Note: At this flow rate assumption the minimum monthly charge will always be exceeded during 1984.

ICG RESOURCES LTD.

Transportation Charges

ICG has received notification from NOVA, AN ALBERTA CORPORATION that all volumes of gas delivered to the Alberta/Saskatchewan border will be subject to the T-5 export service rate.

Forecast:

Assuming a 183.0 10^3m^3/d flow and a \$10.50/10^3m^3 T-5 service rate the annual NOVA charge will be:

183.0 10^3m^3 x \$10.50/10^3m^3 x 365
= \$701,000/year

Schedule 5

ICG RESOURCES LTD.

Return on Rate Base

Proposed Practice

(1) Rate Base

ICG proposes to include the following components in its rate base:

(a) Inventory:

Inventories represent temporary investments in natural gas which can be either positive or negative in value. The Alberta Border Price as it exists from time to time is used to determine the value of inventory.

Due to the unpredictable nature of inventories ICG has not attempted to include such amounts in it's proforma rate base.

(2) Capitalization

ICG proposes to adopt a total debt capital structure for return purposes.

(3) Rate of Return

ICG submits that a rate of return should provide for the recovery of a company's debt costs. ICG's investment is totally debt funded and the availability of debt to ICG is by way of floating prime based bank loans. In order to recognize this variable nature of ICG's debt costs, ICG would propose to calculate it's return on rate base each month using the actual prime rate.

Effect on ICG

Approval of this application would enable ICG to meet it's responsibilities as an original buyer for gas "intended to be removed from Alberta" and provide for the vehicle to recover costs attributable to it's original buyer activities, within Alberta.

Effect on Third Parties

The major beneficiaries of maintaining marketing activities for natural gas are the Producers and the Province of Alberta.

Respectfully submitted
ICG RESOURCES LTD.

by

W.J. Smart
Vice-President, Operations

ICG RESOURCES LTD
DIVISION OF INTER-CITY GAS CORPORATION

2700-140 FOURTH AVENUE S.W.
CALGARY ALBERTA CANADA
T2P 3S3
(403) 231-9000

ROUTE TO	INIT
Chairman	
R.D. Hall	
D.L. Willis	
Admin. Asst.	
G. Man. Finance	
G. Man. E & P.	
G. Man N. Gas	
G. Man. Pet	
Sec & Sol	
Sen Advs. SD & CS	
Auditor	
W. McKain	
K. Lin	
File	

RETURN TO

1984-02-16

HAND DELIVERED

Alberta Petroleum Marketing Commission
#1900, 250 - 6th Avenue S.W.
Calgary, Alberta
T2P 3H7

Attention: Mr. V. M. Thomas,
General Manager, Natural Gas

Dear Sirs:

Re: Application dated 1983-11-01 (Docket No. 83-14) by ICG Resources Ltd. Requesting an Alberta Cost of Service

In response to your letter of 1984-01-31 requesting further information relative to ICG Resources Ltd.'s application for an Alberta cost of service, the following is submitted.

The attached Table 1 is our most recent forecast of expected purchases up to December, 1983. The slower than expected start-up of this new gas market could result in gas purchases for the contract year 1983-11-01 to 1984-10-31 of 1.4 million GJ's compared to the originally anticipated 2.5 million GJ's. No gas purchases occurred in November, 1983 and minimal purchases occurred in December, 1983.

With regard to cost deferrals during months of no or low throughput, it would be ICG's intent to administer the deferrals in the following manner:

-all costs pertaining to the cost of service period in question would be reported as required. On line 18 ICG would process a cost of service adjustment which would take all costs relative to the current month add in all costs from prior deferrals to determine a "base" cost of service. A per unit cost of service would be determined utilizing the current month purchases. If greater than the defined Border Price, then sufficient costs would be removed from the base to determine an "adjusted" cost of service. These deferred costs would incur carrying costs which would be applied for recovery and which would be carried forward to subsequent cost of service submissions.

Deferrals would be outstanding only until sufficient purchases were available to satisfy the ABP ceiling criteria.

It should be remembered that the cost deferral concept is a start-up phenomena and it is anticipated that its use will be the exception as opposed to the norm.

Also attached as requested is an executed copy of the consultant Operator Agreement between ICG Resources Ltd. and Pan-Alberta Resources Inc. dated 1983-08-01.

If you have any further questions regarding our application please contact the undersigned at 231-9030.

Yours truly,

ICG RESOURCES LTD.

W. J. Smart, P. Eng.
Vice President-Operations

/tw

Enc.

c.c. Pan-Alberta Resources Inc..
Attention: Mr. J. Lawton

Table 1

ICG Resources Ltd.
Forecast of Expected Purchases

Month	Volume - $10^3 m^3$	Energy - GJ
November, 1983	-	-
December, 1983*	242.3	9,103
January, 1984	900	34,100
February, 1984	1,830	69,340
March, 1984	4,920	186,420
April, 1984	5,340	202,330
May, 1984	4,310	163,290
June, 1984	3,400	129,000
July, 1984	3,040	115,300
August, 1984	3,270	124,010
September, 1984	3,850	145,820
October, 1984	5,280	200,000
November, 1984	6,880	260,570
December, 1984	8,710	329,890

*Actual

1984-02-16
DRB/tw

Alberta PETROLEUM MARKETING COMMISSION

DETERMINATION 84-20 (WCT)
ALBERTA COST OF SERVICE
NATURAL GAS PRICING AGREEMENT ACT

APPLICATION

By application dated January 10, 1984, Westcoast Transmission Company (Alberta) Ltd. (herein called "Westcoast-Alberta") requests approval for utilizing a rate of return on rate base after income taxes of 12.05 percent in determining its Alberta cost of service for the month of January 1984 and for succeeding months. The application is shown in the attached Appendix A.

DECISION

Effective January 1, 1984, Westcoast-Alberta's rate of return on rate base after income taxes for Alberta cost of service shall be 12.05 percent.

REASONS

The National Energy Board in its Reasons for Decision of August, 1983 approved a rate of return on rate base after income taxes of 12.05% for Westcoast Transmission Company Limited. The Commission has in the past taken into account decisions made by other regulatory bodies exercising jurisdiction over transmission companies operating both within and without the Province of Alberta when such decisions have been consistent with Alberta law and Commission policies relating to Alberta cost of service. The Commission has reviewed the National Energy Board's Reasons for Decision and considers a 12.05 percent rate of return on rate base to be appropriate for Alberta cost of service.

DATED THIS 19th day of June, 1984 at Calgary, Alberta.

M R Pullam

M. R. Pullam
Acting Secretary

IN THE MATTER OF the
Natural Gas Pricing
Agreement Act and the
Regulations made thereunder

-and-

IN THE MATTER OF an Application
by Westcoast Transmission Company
(Alberta) Ltd. respecting the
determination of its Alberta
cost of service.

TO: The Secretary
Alberta Petroleum Marketing
Commission
1900 Bow Valley Square II
250 Sixth Avenue S.W.
Calgary, Alberta
T2P 3H7

APPLICATION

Westcoast Transmission Company (Alberta) Ltd. (hereinafter referred to as "Westcoast Alberta") hereby applies pursuant to Section 2(2) of the Natural Gas Pricing Agreement Act, for a Determination by the Alberta Petroleum Marketing Commission that Westcoast Alberta may, in determining its Alberta cost of service for the month of January 1984 and for succeeding months, utilize a rate of return on rate base after income taxes of 12.05 percent.

In support of this Application, Westcoast Alberta submits the following:

1. Westcoast Alberta was originally incorporated on March 25, 1949, under the laws of the Province of Alberta and was continued under the provisions of the section 261 of the Business Corporations

Act of Alberta by Articles of Continuance issued on November 29, 1983. Westcoast Alberta is a wholly-owned subsidiary of Westcoast Transmission Company Limited ("Westcoast").

2. Westcoast Alberta owns and operates certain gas gathering pipeline facilities located in the Province of Alberta and extending from points in the South Braeburn, Gordondale and Pouce Coupe gas fields to a point in the Province of Alberta near the British Columbia border where they connect with the pipeline facilities of Westcoast. Westcoast Alberta's pipeline facilities are operated under the authority of various licences issued pursuant to the Pipeline Act of Alberta.

3. Westcoast Alberta purchases natural gas under gas sales contracts made with producers in the South Braeburn, Gordondale and Pouce Coupe gas fields, which gas is removed from the Province of Alberta under the authority of Permit No. WC 80-6, issued pursuant to the Gas Resources Preservation Act. Consequently, Westcoast Alberta is an "original buyer" within the meaning of that term as defined in the Natural Gas Pricing Agreement Act.

4. The gas purchased by Westcoast Alberta is, in turn, sold under contract to Westcoast and forms part of the overall supply of gas delivered into the Westcoast pipeline system for sale to the latter Company's domestic and export customers. For pricing purposes, the gas sold by Westcoast Alberta to Westcoast is deemed, both under the Natural Gas Pricing Agreement Act and the Energy Administration Act, to be sold into the United States' export market.

5. While owned and operated by a separate company, the gathering pipeline facilities of Westcoast Alberta are integrally connected

with the pipeline system of Westcoast, since the sole purpose of Westcoast Alberta's facilities is to deliver additional volumes of gas into the parent Company's system to meet overall system requirements.

6. The rate of return on rate base after income taxes presently utilized by Westcoast Alberta in determining its Alberta cost of service is 11 percent, which was approved in the Commission's Determination WCT 78-1 dated February 27, 1978. That rate of return was the same rate of return as that approved for Westcoast's pipeline system as the result of an arbitration in 1977 under the November 13, 1973 Agreement with the British Columbia Petroleum Corporation. In finding that the rate of return awarded to Westcoast was appropriate for Westcoast Alberta's gathering facilities, the Commission took into account the fact that Westcoast Alberta had not raised any capital from external sources with the result that the cost of capital to the parent Company was applicable proportionately to the subsidiary.

7. As was the case in 1978, Westcoast Alberta has not raised any capital from external sources, and all its capital requirements are met through Westcoast itself. Consequently, the Commission's findings in Determination WCT 78-1 respecting the appropriate cost of capital for Westcoast Alberta are equally applicable at this time.

8. Since November 1, 1979, the cost of service charged by Westcoast for the transmission of gas through its pipeline system has been actively regulated by the NEB in accordance with Order No. TG-5-79, as amended. The NEB's latest decision on the appropriate capital structure rate of return for Westcoast is contained in its Reasons for Decision of August 1983, the relevant sections of which are set out in Appendix A to this Application.

The NEB decided that a rate of return on rate base after income taxes of 12.05 percent was appropriate based on a deemed capital structure containing a 35 percent equity component. That determination was made after extensive hearings by the NEB in the late spring of 1983.

9. It is submitted that, applying the approach approved in the Commission's Determination WCT 78-1, the same capital structure and rate of return is appropriate for Westcoast Alberta.

10 . If the amendment requested in this Application is approved by the Commission, Westcoast Alberta's monthly Alberta cost of service would be increased by approximately $2300.

All of which is respectfully submitted.

DATED at the City of Vancouver in the Province of British Columbia, this 10th day of January, 1984.

WESTCOAST TRANSMISSION COMPANY
(ALBERTA) LTD.

Per: ______________________
G.W. Lade
Secretary

All notices and communications in connection with this Application should be directed to the care of G.W. Lade, Secretary, Westcoast Transmission Company (Alberta) Ltd., 1333 West Georgia Street, Vancouver, British Columbia, V6E 3K9.

CHAPTER 7

Rate of Return

Westcoast applied for the following deemed capitalization and before-tax rate of return on rate base for the test year ending 31 December 1983.

TABLE 7-1

	Amount ($000)	Ratio (%)	Cost (%)	Return Component (%)
Balance of External Financing	25,895	3.34	12.97	.43
Long-Term Debt	445,157	57.49	10.80	6.21
Preferred Shares	32,273	4.17	8.50	.35
Common Equity	271,021	35.00	15.90	5.57
	774,346	100.00		
Rate of Return on Rate base after Income Taxes				12.56
Utility Normalized Income Taxes			6.46	
Rate of Return on Rate Base before Income Taxes				19.02

7.1 Deemed Capital Structure

The applied-for capital structure reflects the capital allocation method set out in the Board's November 1980 Decision which was established in order to ensure that the ratepayer did not subsidize non-utility investments. Accordingly, the average test-year utility capitalization was equated to the average rate base plus construction work in progress. The common equity component was deemed to comprise 35 percent of this average capitalization. The remainder of the capitalization was deemed to consist of long-term debt, preferred equity and balance of external financing capital in the same proportions as each is represented in the total amount of long-term debt, preferred equity and balance of external financing capital existing within the corporation. The individual components of the capitalization together with matters relating to the associated capital cost rates are discussed below.

7.2 Balance of External Financing

The term "balance of external financing" refers to debt which the Company has yet to fund on a long-term basis for the 1983 test year. The Company requested that this balance be costed at a long-term rate of 12.97 percent on the assumption that it will be funded on a long-term basis during 1983. However, during cross-examination, it was determined that WTCL has no plans for further long-term issues in 1983 and that it is likely that this balance will continue to be financed during the test year on a short-term basis. It was also determined that corporate policy is to obtain short-term funds from the least cost source, which was stated, in general,to be the commercial paper market. The Company's recently experienced monthly short-term borrowing rates were given in evidence. The Board notes these rates averaged 121 basis points less than the average commercial bank prime rate of 11.69 percent for the first four months of 1983.

BCPC was the sole intervenor to take issue with the Company's proposal for costing the balance of external financing. Its expert witness suggested a long-term rate was inappropriate as Westcoast had already financed this balance for a significant portion of the test year at short-term rates. This witness proposed using a combined short-term/long-term rate of 11.89 percent to cost the balance of external financing. This rate was based on the average commercial bank prime rate for the first four months of 1983 and an estimated long-term rate of 12.00 percent for the balance of the test year.

7.3 Long-term Debt

Westcoast calculated its embedded test year cost of long-term debt to be 10.80 percent and allocated 87.3 percent of its total debt to the utility operation, based on the allocation method set out in the Board's November 1980 Decision. While no intervenor contested Westcoast's estimated embedded cost of long-term debt, CPA/IPAC took issue with the method of allocating long-term debt between utility and non-utility operations.

CPA/IPAC took the position that a large portion of the approximately $110 million in proceeds from the Company's two most recent debenture issues was used to retire bank loans that had been incurred with respect to the acquisition of shares of Westcoast Petroleum, a non-jurisdictional asset. They further noted that these two debt issues carry interest rates of 16.75 percent and 12.5 percent, which are higher than the average rate on the Company's other existing long-term debt. Consequently, CPA/IPAC concluded that if these two issues were to be allocated in the same proportions as all other issues, then the utility operations would bear a higher embedded debt cost rate simply because of the Company's non-utility expansion. CPA/IPAC did not, however, put forward any proposal as to what they felt would constitute an appropriate method by which to allocate the two most recent issues of long-term debt.

During cross-examination, a witness for the Applicant pointed out that the prospectuses associated with the debt issues in question indicated that the proceeds were to be used to finance both utility and non-utility expenditures and that no more than 12 percent of the last two long-term debt issues (i.e. the approximate proportion of total corporate debt allocated to non-utility operations) had been used to repay bank loans related to the acquisition of Westcoast Petroleum shares. Westcoast submitted that it is difficult to trace the dollars from the two debt issues in question. It further argued that if CPA/IPAC felt a revised method of debt allocation was necessary, they should have submitted evidence which would have been subject to cross-examination. In conclusion, the Applicant submitted that there was no basis on which the Board should accept CPA/IPAC's argument.

7.4 Preferred Shares

The preferred share capital contained in the applied-for capitalization was calculated in accordance with the existing approved capital-allocation methodology. The indicated cost rate of 8.50 percent was calculated in a manner consistent with prior applications and was not an issue in these proceedings.

7.5 Common Equity

7.5.1 Common Equity Ratio

The Company applied for a deemed 35 percent common equity component which it indicated was at the low end of the range of reasonableness. It was noted that this is equal to Westcoast's existing approved deemed common equity ratio. The Applicant's two expert witnesses cited the level of Westcoast's business risks, the implicit capital structure of its non-jurisdictional activities, the requirement to have an appropriate balance among the different components of the deemed capital structure and the historical evolution of Westcoast's capital structure in support of the applied-for deemed common equity ratio.

Business risk was said to have increased since the time of the Company's last toll hearing by virtue of the unsettled conditions in the Company's U.S. export markets. However, it was noted during cross-examination that the nature of the BCPC Agreement insulates the Company from declines in market demand. In this regard, the Company's expert witnesses suggested that changes in the economic fundamentals underlying the Agreement called its continued existence into question. However, a witness for the BCPC regarded the possibility of a unilateral abrogation or termination of the Agreement as unlikely, in view of the fact that Westcoast could turn to Alberta for its required gas, leaving the BCPC with gas purchase contracts and no means of transportation. This witness also indicated that he felt investors placed great faith in the Board's statement, made in its 1980 toll decision, that it would wish to review Westcoast's tolls should there be a significant change in the Agreement.

The Applicant's expert witnesses also felt that the business risks confronting the Company had increased due to the possibility of Cabinet review of regulatory decisions such as that which occurred with respect to TCPL in 1982 and due to the possible non-recovery of costs arising out of the Board's application of the Federal Government's "6 and 5" restraint program. With respect to the former point, TCPL had been affected by decisions with respect to domestic pricing made by the Federal Government under the Energy Administration Act. The Energy Administration Act does not authorize the Federal Government to set the

domestic price of gas produced and consumed within the same province such as British Columbia. Decisions by the Board under Part IV of the Act are not subject to review by the Federal Government. With respect to the latter, the witness for BCPC was of the opinion that the "6 and 5" restraint program had had a beneficial effect on Westcoast's stock prices which far outweighed the possible non-recovery of costs that might arise from the implementation of the program. This witness was also of the view that the Company's physical or operating risk had declined since its last toll hearing due to the completion of an $18 million looping program. However, the Applicant's witnesses contended that this program had not had a significant effect on its total operating risk in view of the extent of its remaining unlooped pipeline.

With respect to the implicit capital structure underlying its non-utility activities, the Applicant's witnesses felt that the 35 percent equity ratio deemed for the utility left a residual amount of common equity underpinning the non-utility which was reasonable and did not give rise to cross-subsidization of those activities by the Company's ratepayers.

BCPC's expert witness noted that the acceptance of his recommended common equity ratio of 33 percent would imply a reasonable common equity ratio for WTCL's non-utility investments given that Westcoast Petroleum made up the predominant share of such assets.

The witness of B.C. Hydro was of the view that the applied-for deemed common equity ratio of 35 percent implied a certain degree of cross-subsidization of WTCL's non-utility activities by its jurisdictional pipeline operations. This witness recommended a 30.7 percent deemed common equity ratio which she found by deducting an amount equal to the entire book value of the Company's non-utility investments from the common equity of WTCL's corporate capital structure. The Applicant's witnesses felt the approach taken by this witness to be inappropriate because, inter alia, they believed a utility capitalization should not be computed as a residual and that the result obtained from this approach did not constitute a balanced capital structure.

In regard to maintaining a balanced capital structure, the Applicant contended that the applied-for deemed common equity ratio was appropriate in that it served to provide for the ability to compete reasonably for funds in the marketplace. One of the Company's expert witnesses noted that an examination of the capital structures of other high quality Canadian utilities revealed Westcoast's proposed 61 percent debt ratio to be the second highest in the group. When considered in conjunction with WTCL's relatively low level of preferred stock, this witness felt a 35 percent deemed common equity ratio represented the lower limit of a range of reasonableness.

In considering the requirement to maintain financial integrity via a balanced capital structure, the expert witness for BCPC compared Westcoast with TransCanada and NOVA. He concluded that his recommended 33 percent deemed common equity ratio was acceptable based on his views as to comparative levels of business risk and 1983 pro forma interest coverage requirements.

In considering WTCL's requirement or need to compete for capital, as well as factors relating to the relative business and financial risks of TransCanada, TransAlta Utilities Corporation and Canadian Utilities Limited, the witness for CPA/IPAC asserted that a deemed common equity ratio of 31 to 33 percent could be considered reasonable. Based upon his analysis, the witness recommended the allowance of a 32 percent deemed common equity ratio.

In addition to the factors already discussed, the Applicant's witnesses felt that the historical evolution of the Company's capital structure should be taken into account in determining an appropriate deemed common equity ratio. This position had regard to the assertion that in its earlier, riskier years of operation, Westcoast could only issue debt securities by attaching equity "sweeteners" thereto. This, they concluded, resulted in Westcoast coming to have a common equity ratio higher than would otherwise be the case.

7.5.2 Rate of Return on Common Equity

Westcoast applied for a rate of return on common equity of 15.90 percent as compared to the currently allowed rate of 15.00 percent. A Company witness indicated that this rate had been requested in keeping with Westcoast's objective of meeting governments' calls for restraint, notwith-

standing the advice of its expert witnesses. In this regard, Westcoast presented two expert financial witnesses. One witness recommended a rate of return in the range of 16.25 to 16.50 percent based on his consideration of the equity risk premium, discounted cash flow (DCF) and the comparable earnings approaches to estimating the cost of equity capital. The results of his equity risk premium and DCF analyses led him to adopt a final estimate of the investors' required return (IRR) for Westcoast's transmission operations in the range of 15.25 to 15.50 percent. This range was restated to reflect what he viewed as an appropriate range of market-to-book ratios under current circumstances and resulted in his recommended rate of return on book equity of 16.25 to 16.50 percent. The witness rejected the comparable earnings test as a measure of fair and reasonable rates of return for the test year based on his view that 1983 corporate profit levels and rates of return on book equity will be inadequate.

The Company's second witness recommended a rate of return on equity range of 16.0 to 16.25 percent based on the results obtained from his equity risk premium, DCF and comparable earnings analyses. His comparable earnings approach, based on the book equity returns of what he considered to be groups of comparable risk industrial companies, indicated that these industrials had achieved rates of return ranging from 16.0 to 17.0 percent over the period reviewed, while maintaining adequate average market-to-book ratios. He then judgementally selected 16.25 percent from the lower end of the range as being appropriate for Westcoast, to reflect his expectations of a slow economic recovery and reduced inflationary expectations. The witness' DCF approach suggested a "bare bones" cost of capital, excluding flotation costs, of 15.0 percent. This figure was adjusted upwards to reflect a market-to-book ratio range of 1.15 to 1.25 to permit the Company to achieve a reasonable degree of financial integrity. This led to his recommended DCF range of rate of return on equity of 16.2 to 16.9 percent. He confirmed the reasonableness of this range by a DCF analysis of the cost of equity capital for four electric or gas utilities and two groups of stable industrial companies. In his equity risk premium analysis, the witness used two techniques in deriving a 15.25 to 15.75 estimate of the cost of equity capital, excluding flotation costs. The addition of flotation costs suggested a final cost in excess of 16.0 percent in both instances.

BCPC presented evidence in this matter and recommended a rate of return in the range of 14.0 to 14.5 percent. In advancing the recommendation, its expert witness relied on the comparable earnings, DCF, equity risk premium and capital asset pricing model (CAPM) approaches to estimating the cost of equity capital. His comparable earnings approach was based on a review of historical returns on book equity for a sample of low-risk industrials and for a second sample of Canadian utility and pipeline companies. After adjusting the observed, achieved rates of return on common equity for his two samples downwards to reflect his forecast of reduced inflation rates during the current business cycle, the witness adopted a rate of return range of 13.4 to 14.6 percent for the first sample and of 13.55 to 13.8 percent for the second. He subsequently concluded that the lower end of both ranges would be most applicable to Westcoast. Using two techniques to estimate the utility growth rate, his DCF analysis indicated a "bare bones" cost of equity capital of between 11.8 and 13.2 percent. This range was adjusted upwards to reflect a market-to-book ratio of 1.15 to 1.20 to permit the Company to preserve financial integrity, resulting in a final recommendation in the range of 12.8 to 14.7 percent. The witness' risk premium approach involved calculation of common-over-preferred-equity and common-over-long-term-debt risk premiums. Each risk premium was then added to an appropriate base, adjusting the resulting values back to a before-tax basis where applicable. Giving greater weight to the common-over-preferred-equity risk premium, he adopted a final recommendation in the range of 13.4 to 14.1 percent. His CAPM test indicated a cost of equity capital in the range of 12.6 to 13.5 percent based on a current Government of Canada treasury bill rate of 9.3 percent; an estimated beta of .60 for WTCL's transmission operations; and an estimate of the differential between future stock market returns and treasury bill returns ranging from 5.5 to 7.0 percent.

B.C. Hydro presented evidence during the hearing recommending a rate of return of 14.5 percent. In arriving at this recommendation, B.C. Hydro's witness first adopted a Company witness' estimate of the cost of consolidated common equity of 15.0 percent. This was subsequently adjusted downwards by 50 basis points to reflect a perceived lower level of risk in Westcoast's

utility operations to arrive at her final recommendation.

CPA and IPAC presented joint evidence in this matter and recommended a rate of return of 14.25 to 14.75 percent. In making the recommendation, their expert witness relied principally on the DCF approach and on an analysis of the reasonableness of the equity risk premium implicit in the result obtained from that technique. His DCF approach suggested an IRR range of 13.6 to 14.1 percent, to which he added 65 basis points to permit Westcoast to maintain financial integrity. This resulted in his final recommended range of 14.25 to 14.75 percent. He noted that this range incorporated a 2.5 to 3.0 percent equity risk premium over the long-term Government of Canada bond rate. This margin, in his view, was below traditional historical levels, but he suggested it was in accordance with recent narrower margins which, in his opinion, have evolved due to the advent of high and volatile levels of inflation. Counsel for CPA and IPAC subsequently recommended the lower end of the range as being appropriate for Westcoast.

7.6 Decision

The Board finds it reasonable to equate average test year utility capitalization to average rate base plus construction work in progress. Having regard to the nature of WTCL's utility business risks, the implicit capital structure of its non-jurisdictional activities, the desirability of maintaining a balanced capital structure and the evolution of the Company's capital structure, the Board finds a 35 percent common equity ratio to be appropriate for the test year. In addition, the Board continues to be of the view that the remainder of the Company's capitalization should be deemed to consist of long-term debt, preferred equity and balance of external financing capital in the same proportions as each is represented in the total amount of long-term debt, preferred equity and balance of external financing capital existing within the corporation as a whole.

As regards the balance of external financing, the Board notes that WTCL has no plans for further long-term debt issues in 1983 and that it is likely that this balance will be financed throughout the test year at a rate approximating WTCL's commercial paper borrowing rate. Accordingly, after considering WTCL's experienced 1983 first quarter short-term borrowing rates, and the various forecasts set out in the evidence for the average 1983 commercial prime rate and commercial paper rates, the Board finds a cost rate of 10.0 percent appropriate for the balance of external financing.

The cost rate for long-term debt was computed in the same manner as that used in the 1980 proceeding. The estimated rate for long-term debt was not contested in these proceedings. The Board accepts the applied-for cost rate of 10.80 percent.

The cost rate for preferred share capital financing was not an issue in these proceedings. As a result, the Board approves the indicated cost rate of 8.50 percent.

In considering an appropriate rate of return on common equity, the Board notes that the expert witnesses for the Applicant agreed that there are problems involved in applying each of the various approaches used to estimate the cost of equity capital. The Board is of the view that the determination of an appropriate rate of return on common equity necessarily involves the exercise of judgment. Having regard to all of the evidence presented and the recent decline in the cost of capital environment, the Board finds 14.75 percent to be a fair and reasonable rate of return on the allowed 35 percent deemed common equity ratio.

7.7 Rate of Return on Rate Base

As a result of the above decisions regarding the components of capital structure and the associated capital cost rates, the Board finds that the allowable Rate of Return (exclusive of income taxes) on Rate Base is 12.05 percent.

One twelfth of this percent, namely 1.004167 percent is the rate to be applied to the allowable rate base (net of deferred income taxes) each month in order to determine the dollar value of the Return on Rate Base to be included in the allowable cost of service.

The derivation of the allowed Rate of Return on Rate Base is set forth below:

TABLE 7-2

	Amount ($000)	Ratio (%)	Cost (%)	Cost Component (%)
ance of External nancing	25,780	3.34	10.00	.33
g-Term Debt	443,182	57.49	10.80	6.21
tal Debt	468,962	60.83		6.54
ferred Shares	32,130	4.17	8.50	.35
mmon Equity	265,815	35.00	14.75	5.16
	770,911 [a]	100.00		
te of Return on te Base after come Taxes				12.05

Derivation of total capitalization is illustrated in Appendix VI.

[illegible] appropriate to serve as her final recommendation.

[illegible] presented joint evidence on [illegible] and recommended a rate of return of [illegible] to 14.75 percent. In reaching this recommendation, their expert evidence relied primarily on the DCF approach and on an analysis of the [illegible] of the equity the [illegible] to the [illegible] comparable [illegible]. The DCF approach suggested an [illegible] range of 13.5 to 14.1 percent, to which an added [illegible] basis points to permit maintenance of financial integrity. This resulted in the final recommended range of 14.00 to 14.75 percent. He noted that this range represented a 2.0 to 3.0 percent equity risk premium over the long-term Government of Canada bond rate. This margin, in his view, was below traditional historical levels, but he suggested it was in accordance with recent narrower margins which, in his opinion, have occurred due to the advent of high and volatile levels of inflation. Counsel for CPNI and IPAC subsequently recommended the lower end of the range as being appropriate for Westcoast.

[illegible] Decision

The Board finds it reasonable to equate average test year equity capitalization to average rate base plus construction work in progress. Having regard to the nature of WTCL's utility business risks, the implicit capital structure of its non-jurisdictional activities, the desirability of maintaining a balanced capital structure and the evolution of the Company's capital structure, the Board finds a 35 percent common equity ratio to be appropriate for the test year. In addition, the Board continues to be of the view that the remainder of the Company's capitalization should be deemed to consist of long-term debt, preferred equity and balance of external financing capital in the same proportions as each is represented in the total amount of long-term debt, preferred equity and balance of external financing capital existing within the corporation as a whole.

As regards the balance of external financing, the Board notes that WTCL has no plans for further long-term debt issues in 1983 and that it is likely that this balance will be financed throughout the test year at a rate approximating WTCL's commercial paper borrowing rate. Accordingly, after considering WTCL's experienced 1983 first quarter short-term borrowing rates, and the various forecasts set out in the evidence for the average 1983 [illegible] and commercial paper rates, the Board finds a cost rate of [illegible] percent appropriate for the balance of external financing.

The cost rate for long-term debt was computed in the same manner as that used in the 1980 proceeding. The estimated rate for long-term debt was not contested in these proceedings. The Board accepts the Applicant's cost rate of 10.30 percent.

The cost rate for preferred share capital financing was not an issue in these proceedings. As a result, the Board approves the indicated cost rate of 8.35 percent.

In considering an appropriate rate of return on common equity, the Board notes that the expert witnesses for the Applicant agreed that there are problems involved in applying each of the various approaches used to estimate the cost of equity capital. The Board is of the view that the determination of an appropriate rate of return on common equity necessarily involves the exercise of judgment. Having regard to all of the evidence presented and the recent decline in the cost of capital environment, the Board finds 15.75 percent to be a fair and reasonable rate of return on the allowed 35 percent deemed common equity ratio.

5.7 Rate of Return on Rate Base

As a result of the above decisions regarding the components of capital structure and the associated capital cost rates, the Board finds that the allowable Rate of Return (exclusive of income taxes) on Rate Base is 12.05 percent.

One twelfth of this percent, namely 1.004167 percent is the rate to be applied to the allowable rate base (net of deferred income taxes) each month in order to determine the dollar value of the Return on Rate Base to be included in the allowable cost of service.

The derivation of the allowed Rate of Return on Rate Base is set forth below.